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WASHINGTON, D.C.
AUSTIN, TEXAS

May 11, 2005

Mr. Charles L.A. Terreni
Chief Clerk/Administrator
South Carolina Public Service Commission
101 Executive Center Dr., Suite 100
Columbia, SC 29210

Re: Carolina Power & Light Company d/b/a Progress Energy Carolinas, Inc. – Annual Review of Base Rates for Fuel Costs.
Docket No. 2005-1-E

Dear Mr. Terreni:

Enclosed please find the original and twenty-five (25) copies of the Prepared Direct Testimony of Dr. Jay Zarnikau and accompanying exhibits for filing on behalf of Nucor Steel-South Carolina. Please acknowledge receipt of this document by file-stamping the extra copy and returning it in the enclosed postage pre-paid envelope.

Please let me know if you have any questions.

S. C. PUBLIC SERVICE COMMISSION
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Sincerely,

Garrett A. Stone
D. Cameron Prell

Enclosures
cc: Len S. Anthony, Esq.
Florence P. Belser, Esq.
Wendy B. Cartledge, Esq.
Benjamin P. Mustian, Esq.
Scott Elliott, Esq.

RETURN DATE: OK DD
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BEFORE THE
PUBLIC SERVICE COMMISSION OF
SOUTH CAROLINA

In the Matter of:	)	
	)	
Carolina Power & Light Company d/b/a	)	**Docket No. 2005-1-E**
Progress Energy Carolinas, Inc.	)	
Annual Review of Base Rates	)	
For Fuel Costs	)	

PREPARED DIRECT TESTIMONY OF

DR. JAY ZARNIKAU

On Behalf of

Nucor Steel — South Carolina

May 11, 2005

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I. INTRODUCTION

Q. Please state your name and business address.

A. My name is Jay Zarnikau. My business address is 4131 Spicewood Springs Road, Suite O-3, Austin, Texas.

Q. By whom are you employed and in what capacity?

A. I am the president of Frontier Associates LLC. My firm provides consulting assistance to energy consumers, electric and gas utilities, and government agencies on topics related to energy economics and pricing, utility cost allocation and rate design, forecasting, resource planning, energy efficiency program design and evaluation, and energy and regulatory policy.

Q. Please state briefly your educational background and professional qualifications.

A. I have a Ph.D. degree in Economics from the University of Texas. I completed undergraduate studies in Business Administration and Economics at the State University of New York and McGill University in Canada.

From 1983 through 1991, I was employed by the Public Utility Commission of Texas, where I served as the Manager of Economic Analysis from 1985 through 1988; as the Assistant Director of the Electric Division from 1987 to 1988; and as the Director of the Electric Division from 1988 to 1991.

From 1991 through 1993, I held a faculty-level research position at The University of Texas Center for Energy Studies.

I served as a vice president at Planergy, Inc. from 1992 to 1999. Since 1999, I have been president of Frontier Associates LLC.

I have written a number of reports and journal articles on the topics of energy policy, rate design, and electric utility restructuring. I presently teach graduate-level classes in statistics at the University of Texas as a (part-time) Visiting Professor.

Q. Have you testified in the past as an expert witness?

A. Yes. I have filed testimony before the Public Commission of Texas and the Texas State Office of Administrative Hearings on roughly twenty-five occasions on behalf of the Commission Staff, electric utilities, and various consumer groups. My previous testimony has addressed a variety of topics including the design of industrial tariffs, billing determinants, energy demand forecasting, computer modeling, fuel costs, energy and utility regulatory policy issues, and resource planning. I have also testified before the Railroad Commission of Texas on natural gas-related issues, and before federal and state civil courts in Texas on utility matters.

Q. On whose behalf are you appearing in this docket?

A. I am appearing on behalf of Nucor Steel – South Carolina ("Nucor").

Q. What materials did you review in the preparation of your testimony?

A. In the limited time available in this proceeding, I have reviewed available information that I considered relevant to the issues in this proceeding, including the South Carolina fuel cost recovery statute; direct testimony of Progress Energy Carolinas, Inc. ("PEC"); information provided in response to discovery responses in this case; information from reports filed by PEC and others with various regulatory commissions; information from previous South Carolina proceedings on fuel costs; information from various proceedings in other states on fuel costs; and various publicly-available information on electric utility fuel costs.

Q. What is the purpose and scope of your testimony in this proceeding?

A. The purpose of my testimony is to analyze the application of PEC to change its fuel-related rates and to offer my conclusions and recommendations as to the appropriate recovery of PEC's fuel costs.

II. SUMMARY OF RECOMMENDATIONS AND CONCLUSIONS

Q. Please summarize your conclusions in this proceeding.

A. I have reached the following principal conclusions:

- PEC's proposed 90% fuel rate increase is unprecedented in magnitude in South Carolina, would lead to significant rate shock to South Carolina retail ratepayers, would negatively affect economic development in PEC's service territory, would impair "public confidence" in the regulatory process and PEC's electric service, and would result in "abrupt [and unnecessary] changes in [PEC's fuel] charges to consumers" in South Carolina and should not be approved. *See* SC Code Ann. Section 58-27-865(G).
- PEC's proposal should be examined through a three-part analysis that separately evaluates: (1) PEC's historical fuel costs for the test period (January 2004 through March 2005); (2) PEC's forecasted fuel costs for the forecast period (April 2005 through June 2006); and (3) the appropriate recovery mechanisms for the historical and forecasted costs that are determined recoverable.
- PEC improperly proposes to recover $2,995,513 in transmission charges related to firm power purchases during the historical test period through its South Carolina retail fuel factor (these costs are $21,425,470 on a total system basis). The relevant statute and good regulatory policy require that these costs be excluded from the fuel factor and recovered in base rates as they have been historically.
- PEC fails to properly account for fuel costs associated with sales under its Real Time Pricing ("RTP") rates by failing to assign to these sales the marginal cost of fuel on which the rate is based.
- The amount of time available in this proceeding does not permit interested parties to adequately evaluate the prudence of PEC's actions in addressing the enormous increase in its costs of coal and natural gas.
- PEC's forecasted fuel costs for April 2005 through June 2006 are excessive considering the magnitude of the proposed increase, the significantly increased volatility and uncertainty of gas and coal prices, and questionable

specific fuel forecasts utilized by PEC. As a result, PEC's forecast should not be used as the basis for setting the overall fuel factor in this docket.

- Even if PEC's historical and estimated future fuel costs were entirely recoverable and its forecasts were perfectly accurate, because of the enormity of the proposal, any increase should be phased-in over a period of time to prevent rate shock.
- The magnitude of escalation in PEC's fuel costs suggest that there may be systemic issues that need be to addressed that justify a thorough and comprehensive review of PEC's fuel purchasing practices and all issues that affect PEC's fuel costs.

Q. Please summarize your recommendations in this proceeding.

A. I offer the following principal recommendations:

- PEC should not be permitted to recover the transmission charges associated with certain long-term firm power purchases from the AEP-Rockport and Broad River power plants through its fuel factor, since transmission capacity charges are not and should not be eligible for recovery under the South Carolina fuel cost statute. These transmission charges should continue to be properly recovered through PEC's base rates as they have been historically.
- PEC should be required to assign the marginal cost of fuel and delivery losses under its RTP rates to RTP sales and remove both these costs and sales from the fuel factor calculation.
- Certain issues surrounding the prudence and reasonableness of PEC's historical fuel costs should be separately and fully examined in a future proceeding, since the time constraints of this proceeding do not permit the parties a reasonable opportunity to fully review historical costs. Alternatively, such issues could be explored through a later, extended review phase in this proceeding.
- The Commission should reject PEC's forecast of fuel costs for April 2005 through June 2006 as not sufficiently conservative and as unreliable for

purposes of establishing a fuel factor increase in this docket. The Commission should consider use of the historical test period fuel costs as a reasonable alternative.

- Gradual steps should be taken to moderate the impact of the proposed fuel rate increase upon ratepayers. Any fuel rate increase should be capped at no more than 1/3 of PEC's proposed increase in this proceeding (between 0.4 and 0.5 cents per kWh).
- The Commission should establish a process for a thorough and comprehensive investigation and assessment of PEC's fuel purchasing practices and all other issues that affect PEC's fuel costs.

Q. Please describe the organization of your testimony in this proceeding.

A. My testimony is organized as follows:

- Section III outlines my approach for reviewing PEC's application in this proceeding.
- Section IV reviews the magnitude and components of PEC's proposed fuel rate increase.
- Section V examines the potential impact of the proposed increase upon consumers in South Carolina and discusses means of mitigating some of the impact associated with the proposed increase in PEC's fuel factor.
- Section VI identifies a number of issues surrounding the reasonableness of PEC's historical fuel costs and discusses the need for a separate, future opportunity to review the reasonableness of the historical fuel expenses.
- Section VII examines whether the transmission capacity charges associated with certain firm purchases made by PEC are eligible for recovery through its fuel factor, and recommends disallowing the fixed transmission capacity costs associated with certain purchased power transactions undertaken by PEC.
- Section VIII reviews PEC's treatment of fuel costs associated with sales made through its real-time pricing program.
- Section IX reviews PEC's forecast of future fuel expenses.

- Section X recommends that the Commission initiate an inquiry into PEC's strategies to better control future fuel costs.

III. METHODOLOGY FOR ANALYZING PEC'S PROPOSAL IN THIS PROCEEDING

Q. How should PEC's proposed fuel rate increase be examined in this proceeding?

A. PEC's proposal should be examined through a three-part analysis that separately evaluates: (1) PEC's historical fuel costs for the test period or review period (January 2004 through March 2005); (2) PEC's forecasted fuel costs for the forecast period (April 2005 through June 2006); and (3) the appropriate recovery mechanisms for the historical and forecasted costs determined recoverable.

Q. How should the historical fuel cost review be conducted in this proceeding?

A. PEC's historical fuel costs should be separately reviewed on two grounds:

(1) Are these costs verified and reasonable costs?

(2) Are these costs eligible and appropriately recoverable through the fuel factor?

In determining whether PEC's proposed historical costs are reasonable under the first test, South Carolina law sets the following standard -- whether the costs are "without just cause to be the result of failure of the utility to make every reasonable effort to minimize fuel costs or any decision of the utility resulting in unreasonable fuel costs, giving due regard to reliability of service, economical generation mix, generating experience of comparable facilities, and minimization of the total cost of providing service." SC Code Ann. Section 58-27-865(F).

In determining whether the proposed costs are eligible and appropriately recoverable through PEC's fuel factor in the second instance, South Carolina law specifically identifies fuel costs that are recoverable through the fuel factor. Potentially recoverable "fuel costs" include: (a) "the cost of fuel," (b) "fuel costs related to purchased power," and (c) "the cost of SO2 emission allowances as used and must be reduced by the net proceeds of any sales of SO2 emission allowances by the utility." SC Code Ann. Section 58-27-865(A)(1). "Fuel costs related to purchased power" is further defined in the statute. *See* SC Code Ann. Section 58-27-865(A)(2). Finally, the Commission may reduce recoverable fuel costs by the cost of fuel recovered through off-system sales. *See* SC Code Ann. Section 58-27-865(E).

Q. How should the determination of forecasted fuel costs be conducted in this proceeding?

A. Unlike PEC's historical fuel costs, PEC's projected costs are not actual or verifiable, but are an estimate and inherently inaccurate and uncertain. As a result, these projected costs are far more subject to judgment and unknowable future market behavior. I recommend caution in approving substantial increases on the basis of projections, especially given the magnitude of PEC's proposed historical fuel cost under-recovery and the tremendous volatility in fuel prices currently being experienced nationwide, since such costs can be readily trued-up in a future proceeding.

Q. How should the appropriate mechanisms for recovery of PEC's fuel costs be evaluated in this proceeding?

A. When significant under- or over-recoveries do not exist and significant increases or decreases are not proposed, it is unnecessary to consider alternative rate mechanisms for fuel cost recovery. However, because of the enormous size of the proposed increase in this case, the Commission should consider alternative mechanisms to moderate the impact on consumers and overall economic development. Potential alternatives include implementing such mechanisms as a gradual phase-in of the increase, stretching the recovery of under-recoveries over a number of years, or even creating a regulatory asset whereby these costs can be recovered outside of the fuel factor on a longer-term basis.

In my view, these above alternatives are consistent with South Carolina regulatory policy as set forth in the fuel cost recovery statute which provides that electric utilities should be permitted a reasonable opportunity to recover "their prudently incurred fuel costs as precisely and promptly as possible, in a manner that tends to assure public confidence and minimize abrupt changes in charges to consumers." SC Code Ann. Section 58-27-865(G).

IV. THE MAGNITUDE AND COMPONENTS OF PEC'S PROPOSED INCREASE IN THIS DOCKET

Q. What fuel factor rate increase does PEC seek in this proceeding?

A. PEC proposes a 1.321 cents per kWh (roughly 90%) increase in the fuel factor rate, which would increase it from 1.471 cents per kWh to 2.791 cents per kWh.

Q. How does this increase compare to previous fuel increases?

A. To the best of my knowledge, this proposed increase in fuel factor dwarfs any previous fuel factor increase by any utility in South Carolina. By contrast, the increase recently implemented by South Carolina Electric & Gas Company ("SCE&G") and approved by this Commission, although extremely large, was 0.492 cents per kWh (almost 28%). Another interesting comparison is provided by looking at PEC's last base rate increase in South Carolina. The total increase approved at that time was a $47.8 million increase in PEC's total South Carolina retail rates and charges, as compared to the $98.9 million increase proposed here.

Q. How does the proposed new fuel factor compare to previous PEC fuel factors?

A. It is my understanding that the new fuel factor, if approved at the level proposed, will be far and away the highest fuel factor ever implemented for PEC, or for any other regulated electric utility in the State. It will also be higher than that for any regulated electric utility in North Carolina, where PEC also provides service. Zarnikau Exhibit No. 1 displays the existing and historical fuel factors for each regulated utility in South Carolina for the past few years. Zarnikau Exhibit No. 2 displays PEC's approved South Carolina fuel factor since 1991.

Over the past 14 years, PEC's South Carolina fuel factor has ranged between 1.122 cents per kWh and 1.517 cents per kWh. The fuel factor has, in fact, remained exactly the same for the past 3 years at 1.471 cents per kWh. After this long period of rate stability, the proposed increase to a staggering 2.791 cents per kWh is particularly shocking.

Q. What are the components of the proposed fuel factor increase?

A. The proposed increase consists of three component parts, as illustrated in Zarnikau Exhibit No. 3. First, PEC has calculated an actual historical under-recovery of approximately $30 million through March 2005. This would amount to about 0.4 cents per kWh of the increase. Second, PEC forecasts an under-recovery of about $11.4 million per kWh for the period April 2005 through June 2005, which amounts to another 0.15 cents per kWh. Third, PEC forecasts an actual fuel cost for July 2005 through June 2006 of 2.238 cents per kWh, an increase of 0.77 cents per kWh or about $57.5 million. Thus, most of the proposed increase (0.092 cents of 1.32 cents and $68.9 million of $98.9 million) is based on PEC forecasted numbers and not actual fuel costs.

Q. Please further explain the historical under-recovery.

A. PEC's $30 million dollar under-recovery (as of March 2005) is also the largest South Carolina under-recovery experienced by PEC since the institution of the fuel factor about twenty-five years ago. Of course, if you add in the forecasted under-recovery for April 2005 through June 2005 as PEC does, the amount grows to $41.4 million. The closest past under-recovery in magnitude is the under-recovery in December 2000 of less than $19 million.

Zarnikau Exhibit No. 4 is a reproduction of Exhibit No. 9, the History of Cumulative Recovery Account, from the Report of the Commission's Utilities Department in Docket No, 2004-1-E. As this Exhibit illustrates, typical under-recoveries for PEC have been much smaller in magnitude, although for the period December 1997 forward, PEC has had a significant under-recovery for each period. Since 1997, the average under-recovery at the end of each year has been almost $11.5 million.

Q. How did PEC achieve such a substantial historical under-recovery?

A. PEC began the period with an under-recovery of $5.7 million dollars at the end of January 2004. In May 2004, PEC experienced an enormous spike in fuel costs (the cost jumped from 1.329 cents per kWh in April 2004 to 2.716 cents per kWh in May 2004), increasing the under-recovery to $11.5 million. According to Mr. Coats' testimony, these higher costs were an anomaly, occurring due to the combination of very extreme weather and nuclear and coal plant outages. Higher costs in July and August 2004 lifted the under-recovery to close to $20 million. Costs leveled out until the period from December 2004 through March 2005, where the under-recovery climbed another $10 million over those four months. It should be noted, however, that except for May 2004, the highest monthly cost of fuel for any month during the period was approximately 2 cents in March 2005.

It appears that the under-recovery is partly due to two actions taken by PEC. First, PEC recommended in the 2004 fuel case not to increase the fuel factor for reasons of rate stability. While this was a reasonable action, it did result in a larger under-recovery. Second, PEC requested in late 2004 that the Commission move PEC's fuel proceeding and fuel test period, so that a new fuel rate would not be in effect until July 2005, instead of April 2005. As best I can tell, PEC did not advise the Commission or anyone else of a likely under-recovery or the expected magnitude, when it filed this request in late 2004.

Q. Please further explain the forecast under-recovery for the period April 2005 to June 2005.

A. As I noted previously, PEC forecasts another $10 million under-recovery for the period April 2005 through June 2005.

Q. Please further explain the forecast under-recovery for the period July 2005 to June 2006.

A. Despite the fact that only one month during the historical period had fuel costs greater than 2 cents, PEC projects that the average cost for this projected 12 month period will exceed 2.2 cents per kWh.

V. MODERATING THE IMPACT OF THE PROPOSED INCREASE UPON CONSUMERS IN SOUTH CAROLINA

Q. Does PEC propose anything to mitigate the impact of the proposed increase on South Carolina consumers?

A. No.

Q. When approving changes in rates, should the Commission consider the impacts of the proposed rate change upon consumers and adopt mechanisms to mitigate such impacts?

A. Yes. There are at least two important regulatory ratemaking principles to consider on this issue. First, the principle of rate stability argues for minimizing abrupt changes in rates in either direction. Second, the principle of gradualism suggests that large increases should be implemented gradually or phased-in to reduce rate shock and soften the blow to consumers. Both of these principles are of paramount importance in the context of PEC's proposal in this case.

Q. Please further explain how the issue of rate stability applies in general and in this case.

A. Sharp changes in rates should generally be avoided. Sharp changes in either direction, up or down, diminish consumer confidence in the regulatory process and reduce the ability of consumers to plan and budget for energy expenses. When considering fuel cost recovery, the need for gradualism is particularly important, since fuel costs fluctuate (sometimes wildly), and abrupt adjustments risk a significant degree of harmful and undesirable volatility. The South Carolina fuel cost statute recognizes the need for rate stability by requiring recovery of fuel costs "in a manner that tends to assure public confidence and minimize abrupt changes in charges to consumers." SC Code Ann. Section 58-27-865(G). Both PEC and the Commission applied this concept in the 2004 PEC fuel proceeding, avoiding an increase even though approval of a small increase could have been justified based on the information presented.

At present, PEC has not offered a plan to implement their proposed increase in a manner that will promote rate stability. PEC has also not yet offered an explanation as to why it has suddenly decided to seek an unprecedented large increase, to be recovered over only one 12-month period, after having maintained and recommended fuel rate stability for the past few years. Moreover, if PEC's proposal in this case is approved, it is likely that the enormous increase would be followed by a significant decrease in the year after PEC recovered its under-recovery, causing further instability and uncertainty for South Carolina consumers. This unnecessary and harmful volatility can be avoided by implementing regulatory mechanisms to iron out any increases or decreases over a longer period.

Q. Please further explain how the issue of gradualism applies in general and in this case.

A. Very large increases, as the one proposed by PEC, run a severe risk of rate shock. Rate shock is a phenomenon where the effects of the increase are so significant that they negatively affect consumers' use of the product, sometimes for the long-term. For example, price elasticity and supply and demand principles suggest that pricing the product higher reduces the demand for the product. A significant price increase could result in businesses being unable to continue to produce (or at least reducing the production of) their products that require energy for manufacturing. Similarly, consumers may not be able to afford energy to adequately cool or heat their homes or enjoy their daily lives. By implementing increases over an extended period of time, a sudden and adverse impact can be mitigated by allowing businesses and consumers to adjust to and budget for the change over time.

The principles of rate stability and gradualism are appropriate and important objectives commonly pursued by regulators for this reason. For example, commissions may deviate from a uniform rate-of-return (i.e., the same return paid by each customer class) in order to constrain large rate increases for any given customer class. Commissions may also approve rate structures and billing methods that provide customers with rate stability choices, such as flat rates or levelized bills. The intent is to offer customers the opportunity to minimize payment fluctuations and/or cost volatility.

Commissions also alleviate heavy rate increases by implementing longer cost recovery periods. For example, in rate proceedings to reflect large new investments, commissions often phase-in the impact of the investment. Longer recovery periods and amortizations of various assets also are often used for the same reasons. Finally, commissions sometimes implement or promote rate stability and/or incentives for purely economic purposes, such as for business development or employment creation. In this case, such rates can provide rate reductions in return for capital investment or job growth.

Q. Does PEC's proposed increase in this proceeding impact all consumers equally?

A. In one sense yes, another no. Every consumer (except for consumers under RTP rates) presently pays the same fuel factor. Thus, on a per kWh basis, each consumer will pay the same additional cents per kWh. But this does not tell the entire story. For example, the percentage impact of the increase on consumer rates and bills will vary significantly. To illustrate, for a hypothetical residential consumer who presently pays 8 cents per kWh, the 1.3 cents increase would be a 16% increase. For a hypothetical industrial consumer who pays 6 cents per kWh, the same increase would be 22%. Another way to look at the issue is bill impact. This is affected by the overall load factor of the consumer – that is, how much energy the consumer uses in proportion to demand. Industrial energy consumers tend to use power at much higher load factors, thereby seeing a much higher proportional bill increase.

In short, the proposed increase will fall disproportionately on industrial customers, where the cost of fuel makes up a much larger percentage of their rates and where, due to their higher load factors, they buy many more kWh per kW of demand. For such customers the increase could amount to thousands or even millions of dollars. Thus, a major consideration in evaluating PEC's proposal must be to take into account the potential impact of PEC's proposed increase on existing economic activity in the service territory, as well as the future economic development of the area.

Q. Please discuss how the Commission could specifically moderate the impacts of the proposed rate change upon consumers?

A. There are a number of options available to the Commission to moderate the impacts of the proposed change once the proper actual historical under-recovery through March 2005 is determined (after all proper adjustments and reasonable disallowances are made, as I will discuss later). Options range from spreading recovery of the historical under-recovery over a number of years (or even postponing recovery) to phasing-in any reasonably forecasted increase in fuel costs, and any combination of options in between. In addition, when a historical under-recovery is as large as that proposed by PEC here, it is imperative that the forecasted fuel costs be determined very conservatively, in order to mitigate the overall increase, to ensure that the rates do not over-recover fuel costs, and to provide an incentive to PEC to keep its fuel costs under control.

It is important to recognize that no one knows for certain, and cannot know, the length of the upturn in fuel costs for PEC. Fuel costs could drop significantly and precipitously in a short period time. I am sure that everyone in this proceeding hopes for that event.

Q. What is your recommended approach?

A. My recommended approach is to moderate some of PEC's proposed increase by adopting an overall cap on the fuel rate increase to be implemented in one 12 month period. This would have the effect of phasing-in any fuel cost increases more gradually.

Specifically, I would recommend implementing an overall increase in this case no greater than 1/3 of PEC's proposed increase, or roughly between 0.4 to 0.5 cents per kWh. This fuel rate increase cap: (i) exceeds PEC's proposed amount of actual historical under-recovery for January 2004 through March 2005, (ii) exceeds a 25% fuel rate increase, and (iii) is in the same ballpark as the amount allowed SCE&G in its recent 2005 fuel rate review proceeding. The level of the cap is of course a judgment call that the Commission ultimately must make, but such a recommendation is both reasonable in terms of allowing for a significantly increased recovery by PEC while still avoiding an enormous increase in rates that could potentially lead to an adverse rate shock for consumers.

If a capped rate increase is adopted and if PEC's average fuel costs for the 15-month forecast period ultimately turns out to be equal to the average for the 15-month historical period, then PEC will fully recover its fuel costs and begin to make a dent in the under-recovery. If not, then the Commission can phase in another gradual increase next year. This approach can be expected to gradually catch up with PEC's fuel costs and bring them into balance; although it may not accomplish this objective overnight.

In the event the Commission does not adopt some form of a cap on the fuel increase in this proceeding, then I recommend, at a minimum, that the Commission approve any rate increase by: (i) utilizing very conservative projections of fuel costs during the period April 2005 through June 2006; (ii) deferring the entire 40 million dollar expected historical under-recovery for at least one year and then permitting recovery gradually over two or three years; and (iii) considering other alternative mechanisms for moderating the rate impact on consumers.

Q. Are there precedents for moderating fuel increases and/or not permitting full recovery of under-recoveries in the next 12-month period?

A. Yes. As I noted above, in the previous 2004 PEC case, the Commission did not implement an increase despite the existence of expected under-recoveries. Similarly, in the recent 2005 SCE&G case, recovery of some of the historical under-recovery was effectively postponed for a year. Further, PEC itself chose to postpone the present proceeding and retain the same fuel factor for three additional months late last year despite having significant under-recoveries.

Q. Are you recommending that the Commission adopt the same approach as was used in the recent SCE&G fuel rate proceeding?

A. No. I think the SCE&G result is precedent for the principle that a public utility's one-year fuel factor need not be set to recover the entire historical under-recovery and expected forecast period fuel costs. The present case involves a significantly worse problem, with a proposed increase of between 2 and 3 times what was adopted for SCE&G. Moreover, the SCE&G case was the result of a settlement by all parties. There is no indication that the Commission itself would have reached the same exact result if the matter had been presented without a settlement.

Q. Are there other actions PEC could take to mitigate the effects of this increase that you would recommend?

A. Yes. There are many other actions PEC could take. For example, in the past PEC has requested the Commission approve proposals to write-off regulatory assets and more to rapidly accelerate depreciation on its nuclear plants. The net effect of these approaches has been to reduce PEC's long-term costs, keep base rates stable and maintain reported regulatory returns by PEC at reasonable levels. PEC could voluntarily offer to create a regulatory asset of some or all of the excess fuel costs and have those costs amortized over some period. This would effectively transfer these costs to base rates and serve the same objectives as past rapid amortizations and depreciations, while continuing more stable overall rates.

VI. REASONABLENESS OF HISTORICAL FUEL EXPENSES

Q. Have you had an opportunity to fully review the reasonableness of PEC's historical fuel expenses?

A. No. Given the ambitious deadlines established for this proceeding, I have had a very limited opportunity to conduct discovery and fully explore the reasonableness of PEC's historical fuel expenses, particularly the reasonableness and prudence of PEC's actions in response to escalating fuel costs. I would not be as concerned regarding this annual review if PEC's fuel costs had not escalated so significantly and so rapidly.

Q. Even without time to review the reasonableness of PEC's historical fuel expenses, have you identified some issues that may merit further review?

A. Yes. There are certain issues that I believe may warrant further examination by the Commission, including the following:

- Has PEC examined whether it could reduce coal costs by purchasing coal from other regions, such as from the Powder River Basin, for example? Presently, coal produced in regions outside of the Appalachian basins is less expensive than coal produced in Appalachia (at least before transportation costs are considered) and many other utilities are switching to cheaper Western coal (e.g., some of Georgia Power Company's coal plants). However, without time for further review, it is presently unclear to me whether higher transportation costs and any equipment changes necessary to burn coal with different quality attributes would negate any potential savings.

- Has PEC pursued all legal means to recover its increased generation costs associated with recent coal delivery disruptions?
- Has PEC aggressively pursued pollution control investments that would result in lower emissions, lower SO2 emissions credit costs, lower fuel costs (due to the ability to use higher sulfur coal) and consequently lower fuel rates?
- Has PEC evaluated and adopted appropriate fuel cost hedging practices and did PEC respond to any advance signals of higher fuel prices with reasonable action?
- Has PEC established the appropriate fuel and resource mix to minimize the long-term cost to consumers and reduce the risks of unexpected fuel price increases?

Presently, I can draw no conclusions whether PEC's actions on any of these issues were prudent and reasonable or otherwise. Even if they acted prudently on historical basis, the issue remains whether PEC should take actions now to address some of these issues.

Q. Given that you have not had an opportunity to fully review the reasonableness of PEC's historical fuel expenses, how do you recommend the Commission treat these costs for ratemaking purposes?

A. I believe that issues concerning the reasonableness of PEC's historical fuel expenses should be deferred to another proceeding and that the parties be permitted an opportunity to review these, and other, issues more extensively. One option would be to proceed with setting a fuel factor in this docket on the assumption that the costs are reasonable, but reserve the historical reasonableness/prudence issues for further review by establishing a separate schedule and hearing that will enable a thorough and complete opportunity to assess how this fuel cost increase occurred and whether PEC has acted reasonably in dealing with it. Another option would be to establish a separate proceeding to assess this issue or defer it to the next fuel proceeding.

VII. REMOVAL OF TRANSMISSION CAPACITY CHARGES FROM HISTORICAL FUEL EXPENSES

Q. Has PEC included transmission capacity charges in its historical fuel costs?

A. Yes. As part of its proposed fuel factor, PEC has included transmission capacity charges related to two long-term firm generation capacity purchases – purchases from AEP-Rockport and Broad River.

Q. What is the amount of these costs?

A. PEC's response to ORS-1-6 indicates that $587,500 per month or $8,812,500 in transmission capacity charges associated with the purchase of power from AEP-Rockport during the historical review period are included in PEC's proposal. Also, $12,612,970 in transmission capacity charges associated with the purchase of power from Broad River is included. According to PEC's response to ORS-1-18, these are firm "take or pay" contracts. On a total system basis during the historical period, these transmission charges incurred by PEC related to these two firm purchases equal $21,425,470. S*ee* PEC response to ORS-1-25.

The South Carolina portion of these costs can be determined by dividing PEC's total South Carolina retail sales by its total system sales for the period, and then applying that percentage to PEC's transmission costs for these firm purchases. Specifically, PEC has included $2,995,513 in historical transmission costs related to these firm purchases within its proposed fuel factor.

Q. Are these same types of costs also included in the projected period?

A. Yes. Since the purchases continue throughout the projected period and well into the future, PEC has included such costs in its projected costs as well. As a result, this issue is important not only for the historical review in this case, but for many future proceedings.

Q. How does PEC support recovery of its transmission capacity charges related to these firm generation capacity purchases through its proposed fuel factor for the historical and forecasted periods?

A. PEC stated in response to NUC-1-27 that the newly amended fuel cost statute in South Carolina permits PEC to include the "total delivered costs" of firm generation capacity purchases within its fuel clause and that transmission costs were included in these costs.

Q. Do you agree with PEC's reading of the newly amended South Carolina fuel cost statute, and are these transmission costs eligible for recovery through the fuel factor?

A. No, under my reading of the South Carolina statute, transmission charges related to firm generation capacity purchases are not eligible for recovery through PEC's fuel factor. Based on my reading, yes, a public utility is entitled to recover its "total delivered costs" related to firm purchased power. However, just as plainly, all capacity-related costs incurred relative to these purchases are excluded from recovery, which by definition excludes transmission charges.

Q. Please explain.

A. As I noted earlier, the South Carolina fuel statute specifies the costs permitted to be recovered in the fuel factor. The section addressing the issue of fuel costs of purchased power, Section 58-27-865(A)(2), was amended in 2004. This section clarifies the definition of eligible recoverable fuel costs related to purchased power, stating: "In order to clarify the intent of this section, "fuel costs related to purchased power"... shall include:

> costs of "firm generation capacity purchases", which are defined as purchases made to cure a capacity deficiency or to maintain adequate reserve levels; costs of firm generation capacity purchases include the total delivered costs of firm generation capacity purchased and **shall exclude** generation capacity reservation charges, generation

> capacity option charges, and **any other capacity charges**; [emphasis added]

Based on a plain reading of this clarification, fuel costs related to purchased power include the total delivered costs related to firm generation capacity purchases, exclusive of all capacity-related costs. By excluding "any other capacity charges" from its definition of fuel costs, in my view, the General Assembly expressed its intent that capacity-related transmission costs should not be recovered through a public utility's fuel factor because capacity-related transmission costs are capacity-related costs entirely separate from purchased power costs. Transmission costs are appropriately and properly recoverable only through PEC's base rates, just as they have historically been recovered. I would also note that if transmission costs were meant to be included, the statute could have specified these costs – after all, it did specifically identify transmission costs for economy purchases in the next section of the statute.

Q. What supports your interpretation that the newly amended statute excludes transmission costs associated with firm power purchases from the definition of recoverable "fuel costs related to purchased power?"

A. In the regulation of transmission service at the federal level and in common industry practice, transmission charges are charges for capacity. Indeed, this Commission treats a utility's own transmission costs as capacity costs. As a result, they are typically excluded from recovery under fuel adjustment mechanisms. The Federal Energy Regulatory Commission ("FERC") stated in Order No. 888, the order establishing the parameters for transmission service in the United States:

> [i]ndeed, when they are not using their reserved capacity, firm transmission customers remain obligated to pay the utility a reservation charge that covers all of the utility's fixed costs associated with the reserved capacity." FERC Order No. 888, 75 FERC 61,080 (1996), as amended by Order No. 888-A, Order on Rehearing, issued March 4, 1997, 78 FERC 61,220 (1997).

In other words, transmission customers pay for the right to capacity – that is the right to use space on the transmission line. This is a similar concept to paying capacity charges for generation – the right to use or call upon the output of the generator. Transmission charges are generally capacity-related costs and are entirely separate from the fuel costs incurred to generating the purchased power.

It is also revealing that PEC itself considers transmission charges to be "capacity charges." For example, under Schedule 7 of PEC's Open Access Transmission Tariff (generally referred to as the "OATT"), which defines what PEC as a transmission provider charges its transmission customers for firm point-to-point transmission service, daily, weekly, and monthly period transmission charges within the PEC zone are based on a price-per-MW "of Reserved Capacity." Similarly, Schedule 8 of the same tariff sets forth charges for non-firm point-to-point transmission service on a price-per-MW "of Reserved Capacity." Schedule 11 of the same tariff uses the same basis for charging for long-term and short-term network contract demand transmission service. Relevant pages of PEC's OATT are contained in Zarnikau Exhibit No. 5.

Q. How would you recommend PEC recover its transmission costs related to these firm generation capacity purchases?

A. Because capacity-related costs are plainly not "fuel costs" within the definition of Section 58-27-865(A)(1)(a), all transmission costs related to firm generation capacity purchases are appropriately recovered through PEC's base rates, as they have been recovered historically. In fact, the AEP-Rockport purchase has been in place for ten years and it is my understanding that such costs were recovered through the base rates prior to the amendment to the statute. The Commission should continue to exclude these costs from the historical and forecasted fuel costs.

Q. Does this issue have importance beyond this case?

A. Yes. The Commission's approach to this issue could establish the long-term treatment of these costs. As a result over the next few years, PEC's customers could be required to pay tens of millions of dollars more through the fuel clause for costs they are already effectively paying for in base rates.

Q. Are there good regulatory policy reasons why it would not be appropriate to interpret recoverable "fuel costs related to purchased power" to include transmission costs related to firm power purchases?

A. Yes. Like the AEP-Rockport and Broad River purchases, these types of firm reliability purchases are typically longer in term and are intended as a replacement for PEC building its own generation. If PEC builds its own generation, both the capital cost of that generation (generation capacity cost) and any transmission costs (transmission capacity cost) would be recovered by PEC in its base rates, just as it does for all its other non-fuel related costs. The treatment should not be different simply because a utility elects to purchase firm power from another generator rather than building its own. The fuel statute recognizes this by not allowing the utility to pass such generation or transmission capacity costs, which have nothing to do with fuel costs, through the fuel factor.

Further, it is generally accepted that transmission-capacity costs should be allocated on a demand basis. For example, this Commission has historically allocated PEC's transmission costs on this basis. The reason for this is that transmission investment is related to peak demand requirements, not energy or average demands. To include transmission-capacity costs in a fuel rate that is part of the energy charge is tantamount to classifying such charges as energy-related. Such policy is not only contrary to standard cost allocation practice but also burdensome to higher load-factor customers who subsequently incur a disproportionate share of corresponding costs.

Q. Does it matter whether these purchases were in effect when PEC had its last general rate case?

A. No. PEC's base rates adequately cover all of its non-fuel costs or it will file for a base rate increase. Even though these costs, as well as many others, had not been incurred when the last rate case was held, many of PEC's costs that were included in that case have changed or been reduced or eliminated and, of course, PEC has experienced significant load growth that produces additional base rate revenues that can cover additional costs. In other words, PEC has recovered these costs in the past through base rates, since if it had not, it would have elected to file a rate increase. Allowing them to recover these costs again in the fuel rate would amount to double-recovery.

Q. How do you explain the difference in treatment for economy energy, where the statute expressly allows recovery for transmission costs?

A. For economy purchases of energy, the statute allows recovery of both generation and transmission costs, but only in the circumstance where the utility's "avoided variable cost" exceeds the "total delivered cost" of such purchase. This amendment was apparently intended to clarify treatment of an issue that had been raised before the Commission and raised on appeal (unlike the transmission issue for firm purchases). My assessment is that these economy energy related transmission costs are permitted to be recovered to encourage utilities to make economy energy purchases where the total costs of such purchases are less than the fuel costs to the utility to generate the energy. Obviously, economically this is an efficient result and the legislative concern could have been that South Carolina utilities would not make the purchases without the right to fully pass the cost through the fuel factor. The difference between not allowing recovery of transmission costs for firm purchases and allowing recovery for economy purchases is that consumers are protected from paying for these capacity costs except where such total costs are less than the fuel cost the utility would have otherwise incurred and passed through the fuel factor.

VIII. PROPER FUEL ACCOUNTING FOR REAL-TIME PRICING PROGRAM SALES

Q. Describe PEC's Real Time Pricing rate?

A. PEC offers a real time pricing program in South Carolina and North Carolina. The South Carolina program is provided under Schedule LGS-RTP-6. Copies of the South Carolina and North Carolina rate schedules are attached as Zarnikau Exhibit No. 6. Under these schedules, the customer pays an RTP hourly energy charge that includes the Marginal Energy Cost, which is defined as including "marginal fuel, variable operating expenses, and delivery losses."

Q. How has PEC treated the fuel costs it incurs and recovers under its RTP rates?

A. According to PEC's response to NUC-1-33, RTP energy sales and fuel costs are treated in the same manner as other general service retail sales. A copy of PEC's response to NUC-1-33 is contained in Zarnikau Exhibit No. 7.

Q. Is this an appropriate treatment for fuel costs incurred and recovered under an RTP rate?

A. No.

Q. Please explain how the fuel costs incurred and recovered under PEC's RTP rates should be treated.

A. PEC should assign the *marginal* fuel cost and losses that are included in the RTP hourly prices and that are incurred by PEC in serving RTP customers to the RTP customers consistent with the pricing program. Specifically, this could be accomplished either by: (a) removing RTP sales and the hourly marginal fuel cost and delivery losses from the system fuel cost calculation or (b) removing from system fuel cost the difference between (i) the hourly marginal fuel cost and delivery losses and (ii) the average fuel cost.

Q. Would your proposed treatment affect the price actually paid by such customers?

A. No. Such customers already pay the hourly marginal fuel cost and delivery losses in their rate; my proposal would simply ensure that these payments are properly credited to fuel costs in order to reduce the cost of fuel to the other customers.

Q. Please explain why this treatment would be appropriate.

A. The whole purpose of RTP is to provide energy consumers with prices that better reflect the changing short-run marginal cost of providing electricity to the consumer, thereby encouraging them to make economically efficient consumption decisions. Marginal fuel cost is one component of the total short-run marginal costs that are incurred in providing electricity to the consumer. Since RTP customers are paying rates based on this marginal cost of fuel (and losses), then it is appropriate that this marginal cost of fuel (and losses) is actually assigned to these sales. Otherwise, these incremental sales will increase the fuel costs and fuel factor for other customers while PEC keeps the difference between the average fuel factor and the marginal cost of fuel for these sales.

Q. Have you calculated an adjustment to reflect this recommendation in the historical fuel costs in this proceeding?

A. According to PEC's response to NUC-1-33 (b), the data required to make this adjustment is confidential. While it is available for review in PEC's offices, it would be impractical for anyone to attempt to perform this calculation without actual data files, since an adjustment would require manipulation of hourly marginal fuel cost data and hourly RTP program sales. It makes more sense for the Commission to require PEC to make this adjustment.

As a result, I suggest that the Commission order PEC to perform the necessary calculations and revise the historical fuel costs and under-recovery accordingly. I also recommend that the Commission order PEC to treat fuel costs incurred in serving RTP customers in the manner that I have described on a going-forward basis.

Q. Can you illustrate the impact of this recommendation?

A. Yes. PEC has a significant amount of sales priced under RTP rates – for the historical test period in this case, these sales amounted to 1,142,701,859 kWh. As a hypothetical illustration, assuming just a one cent per kWh difference between average monthly marginal fuel costs and average monthly fuel costs (which is probably quite conservative), this adjustment would produce a $11,427,019 reduction in system fuel costs and a $1,597,621 reduction in South Carolina jurisdictional fuel costs.

IX. PEC'S FORECAST OF FUEL COSTS

Q. Has PEC forecasted its average monthly cost of fuel for April 2005 through June 2006?

A. Yes. This information is contained in Barkley Exhibit No. 4. PEC's forecast appears to be derived from a computer simulation that generates this average fuel cost based on projections and assumptions as to the price of various fuels, purchased power, transmission costs, SO2 emission allowances and simulated operation of PEC's generation system.

Q. Does this approach accurately establish future fuel costs?

A. No. The forecast is entirely dependent on the various assumptions on which the computer model is built and the assumptions as to all of the inputs. Utilities Department Exhibits No. 6 and No. 9, produced by the Commission Staff in past PEC cases, illustrate the historical inaccuracy inherent in this type of forecasting. I have included these Staff exhibits from 1998 to the present in my Zarnikau Exhibit No. 8. These forecasts become particularly suspect when the underlying assumptions, such as the price of fuel, is subject to significant volatility. The effects are demonstrated in the average monthly fuel costs for the historical test period in this case. While in the last proceeding PEC under-forecasted these costs, it is just as likely in this case they over-forecasted these costs, depending on the effects of such volatility.

Q. Has PEC provided a forecast of the price of acquiring coal, natural gas, and other fuels over the next 15 months?

A. Yes. Projections of total fuel costs were provided by PEC in response to ORS-1-4. Projections for various types of fuels are provided in PEC's response to NUC-1-43 (confidential) and through some other documents.

Q. Are there uncertainties inherent in PEC's forecast of future fuel prices?

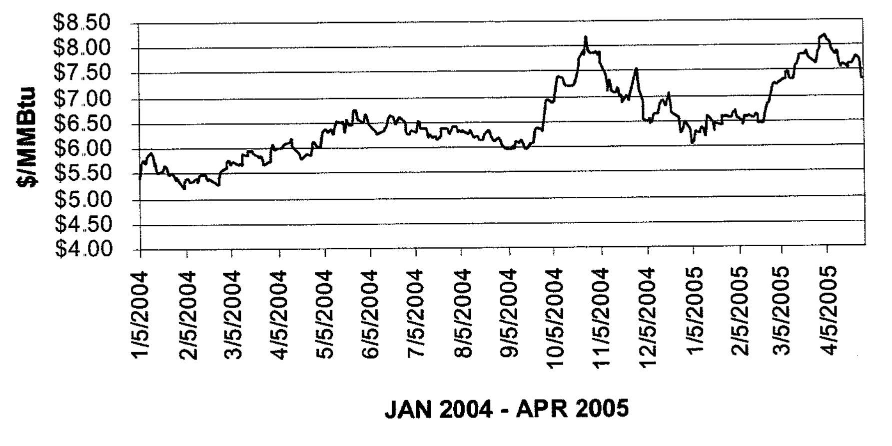
A. Yes. The inherent uncertainties are particularly acute in light of the volatility that fuel prices have exhibited in recent months. It should be clearly understood that volatility does not necessarily mean higher prices – it can also mean lower prices when prices drop.

Q. Please describe this recent volatility.

A. Volatility in fuel prices is readily exemplified by recent forward prices for natural gas. Natural gas is chosen for illustration simply because ample public price data are available and also because natural gas prices affect coal use and costs.

Figure 1 below illustrates 12-month Henry Hub (a trading location in Louisiana at which prices are commonly quoted) price strips, by trade date, from January 2004 through April 2005 (Data source: www.enerfaxdaily.com). A 12-month strip is the simple average of the next 12-forward prices, in this case the simple average of the next 12 forward gas prices listed for Henry Hub gas. Despite the fact that the depicted prices represent 12-month averages, it is clear that gas prices have fluctuated significantly in the past seven months, twice reaching relative of peaks of over $8/MMBtu. Equally interesting is the fact that the first $8 price spike is followed by a relatively rapid price descent. Keep in mind that the price fluctuations exhibited in Figure 2 are a relatively recent phenomenon as gas prices generally moved within a relatively narrow range in the 1980s and 1990s.

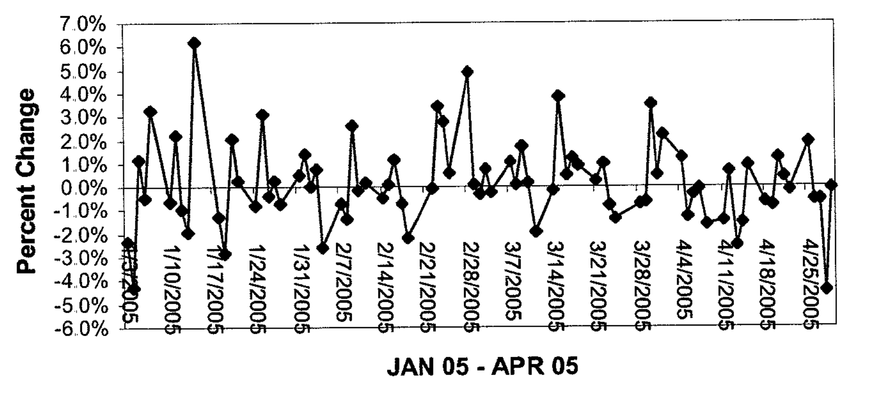
Figure 1: Henry Hub 12-Month Price Strips



Q **To what extent have 12-month gas price strips fluctuated in 2005?**

A. Figure 2 below illustrates the daily percentage price change in 12-month price strips from the beginning of 2005 through the end of April 2005. The figure shows frequent price swings of two or more percent on a daily basis. In addition, the price swings are equally likely to move in either direction. The key point is that even for 12-month averages there is substantial bi-directional price movement in the current gas market.

Figure 2: Daily % Change In 12-Month Price Strips



Q. Have coal prices also fluctuated in recent years?

A. Yes. A recent conference earlier this year in Denver, Colorado, "Coal: Volatile Markets & New Fuel Supply Patterns," presented numerous graphs on coal market price movement. Zarnikau Exhibit 9 includes one of the conference's graphs, a chart illustrating price volatility for different coal markets and Henry Hub Gas. The graph, which was presented by PACE | Global Energy Service, illustrates spot price movement over the five-year period beginning January 1999 and ending July 2004. Zarnikau Exhibit 9 reveals that Henry Hub prices exhibit significant price movement with Central Appalachian coal ("CAAP") prices also illustrating considerable volatility. Conversely, the least volatile market is Powder River Basin Coal ("PRB").

Q. How does this recent fuel price volatility affect the accuracy of projections of future fuel prices?

A. It is intrinsically more difficult to forecast the values of a variable (e.g., coal prices or natural gas prices) with volatile patterns. As discussed in Mr. Coats' direct testimony, a set of unusual, and in some cases unprecedented factors have converged to drive up coal prices in recent years, including bankruptcies of coal suppliers, growing demand for coal in Asia, coal transportation problems, and flooding in early 2004. Some of these factors will not necessarily exist in the future. In recent years, it has become unusually difficult to forecast coal prices. Indeed, the accuracy of PEC's coal price forecasts has declined. Based on PEC's response to NUC-1-38(a) the coal price forecasts relied upon by PEC in November 2003 and April 2004 anticipated market prices for CAAP coal in the $30 to $36 per ton range (depending upon coal quality) for 2005. By August 2004, these projections were increased to the $53 to $61 range. Projections relied upon by PEC in November 2004 projected coal prices for 2005 in the $55 to $65 range. The most recent (April 2005) internal projections provided by PEC anticipate CAAP coal prices to be in the $51 to $62 per ton range for this year. PEC's response to NUC-1-38 is attached to my testimony as Zarnikau Exhibit 10.

In addition, as PEC's response to NUC-1-14 reveals, the outside sources that PEC relies upon for fuel price forecasting information have recently changed their forecasts of future coal prices on numerous occasions.

Q. Do PEC's most recent forecasts anticipate change in today's high coal prices?

A. Yes. The April 2005 coal price forecast provided by PEC in response to NUC-1-38(a) anticipates a declining trend in Central Appalachian coal prices over the next few years. For example, Central Appalachian compliance coal is expected to decline in price from $61.67 per ton in 2005 to $42.25 by 2009. Thus, PEC's own projections suggest that coal prices will soon decline. I recognize that PEC's coal costs do not exactly mirror spot market coal prices, due to the presence of contracts. Nonetheless, I believe that it is important to recognize this forecasted trend. Moreover, the fact that suppliers have been willing to negotiate supply contracts with PEC at "below market prices" suggests that suppliers believe that higher prices cannot be maintained. *See* Coats Direct Testimony, at 16. After all, reasonable suppliers would only negotiate "below market" prices if they thought there was a real likelihood that market coal prices would drop.

Q. What is your impression of the reasonableness of PEC's forecast of natural gas prices?

A. I have not conducted a detailed review of PEC's natural gas prices due to limited time. Nonetheless, I would note that Mr. Coats indicates that PEC projects much higher gas prices for the forecast than present market prices. For example, market prices for summer are presently in the $6.60 to $7.00 range and the NYMEX average monthly settlement price for July 2005 to June 2006 as of May 10, 2005 was $7.28. These prices are included in Zarnikau Exhibit No. 11. Yet Mr. Coats indicates PEC projects an average commodity cost of $8.89/Dt for this period. This $1.61/Dt difference is large enough to significantly question PEC's natural gas price projections and further suggests that PEC's projection of fuel costs for the coming months is unreasonably high. As an aside, it should be noted that

NYMEX prices constantly change, but this snapshot is one indication of what the market expects future prices to be.

Q. Are there other flaws and issues with this forecast that you have identified in your limited time?

A. Yes. PEC appears to assume that it will achieve no success with the Surface Transportation Board on its appeal. *See* Coats Direct Testimony, at 18. While it is true that no one can "predict the outcome," no one can predict the outcome of the other costs PEC predicts or forecasts. Under the circumstances, some adjustment reflecting the likelihood of success should be included in the projected costs. Second, the projection needs to be adjusted lower to exclude on a forecasted basis the costs that I have recommended be excluded on a historical basis (e.g., transmission capacity costs and costs related to RTP sales). There are likely other issues that I have not had the opportunity to identify in the limited time available in this case.

Q. In light of all of the uncertainties inherent in PEC's forecast and the projections of declining coal prices over the next few years, and the impact of the proposed increase on consumers, how should the Commission use this forecast?

A. I recommend that the Commission act cautiously and conservatively with regard to the amount of *additional* increase that it approves based on *forecasted* fuel prices. Absent the establishment of a means of extending the recovery period for the under-collection during the 15-month review period or significant disallowances, ratepayers already face a very significant price increase merely for the collection of historical under-recoveries. Given that PEC's future fuel costs are quite speculative and will eventually be trued-up, I believe that the Commission can exercise some latitude in its consideration of the amount of the projected increase to reflect in the fuel price.

In other words, I would not recommend relying on PEC's forecast for projected fuel costs for April 2005 through June 2006. With additional time, one might be able to correct some of the deficiencies. However, that option is foreclosed. As a result, if the Commission adopts the cap I proposed earlier, it will effectively be limiting the forecasted fuel costs in this proceeding. Of course, the Commission also has the option of setting expected future fuel costs based on the historical costs recently incurred by PEC. In concept, this approach is no different than using a historical test period to set future base rates, which I understand is this Commission's policy. Average fuel costs for the historical test period were 1.737 cents per kWh prior to any adjustments. Zarnikau Exhibit No. 12 calculates this historical test period fuel cost. As I have noted, PEC will eventually and assuredly recover its reasonable fuel costs regardless of what projection is used; however, the resultant rate shock from the fuel rate increase will be substantially lessened using a more conservative forecast.

X. FUTURE ACTIONS BY PEC TO CONTROL FUEL COSTS

Q. In light of the magnitude of PEC's escalating fuel costs, what are your comments?

A. On the positive side, in recent years, PEC has not only achieved stable nuclear operations and output, but actually expanded its capabilities. Hopefully this will continue. However, the actual cost increases reviewed in this proceeding, not to mention the projections supplied by PEC, give great cause for concern as to the level of its other fuel costs in the future. PEC needs to take immediate and decisive action to get these costs under control. For example, if CAAP coal is in such tight supply as indicated by Mr. Coats, then PEC needs to carefully evaluate and invest in, as necessary, the ability to burn other types of coal. Given the cost of natural gas burned by PEC for generation from IC turbines, PEC should be evaluating and pursuing other lower-cost generation alternatives, including potentially purchasing or constructing additional coal-fired power. PEC's power purchase and sales practices should be carefully evaluated to ensure that they result in the lowest reasonable fuel cost for PEC's system ratepayers. Given the issues of environmental compliance, PEC should move forward its installation of pollution-control equipment as soon as possible, while demonstrating to the Commission that its emission allowance purchasing practices are reasonable.

Q. What should the Commission do to address these concerns?

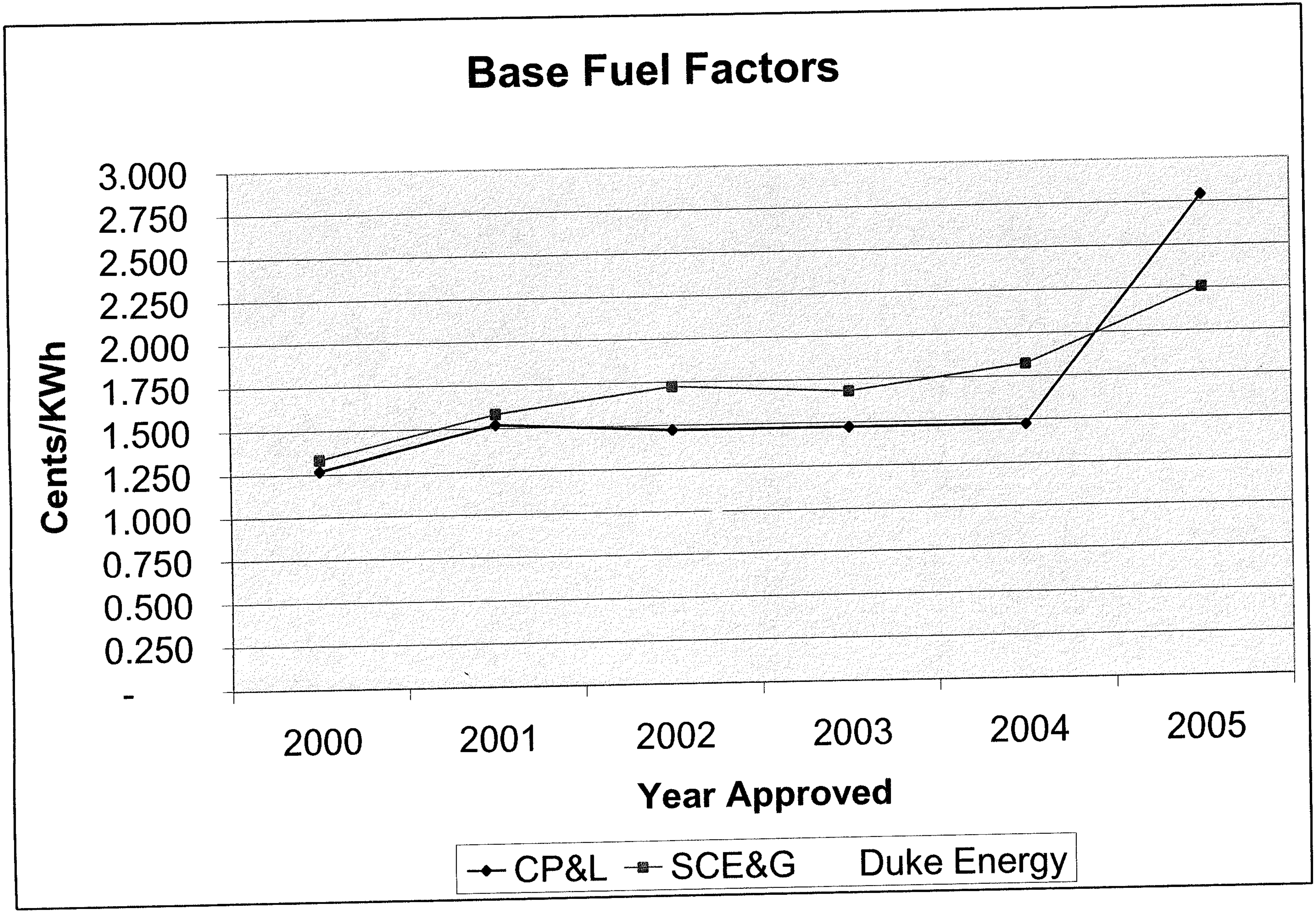
A. My understanding is that the Commission approved and ordered a study of SCE&G's fuel and fuel-related practices by the Office of Regulatory Staff. This type of study would also be appropriate for PEC. I strongly recommend that interested parties in this proceeding also be actively involved in this process. In addition, however, PEC should be put on notice that it needs to do everything possible to ensure that its fuel costs are under control.

Q. Does this conclude your testimony?

A. Yes.

ZARNIKAU

EXHIBIT NO. 1


Base Fuel Factors
Cents/KWh
3.000
2.750
2.500
2.250
2.000
1.750
1.500
1.250
1.000
0.750
0.500
0.250
-
2000
2001
2002
2003
2004
2005
Year Approved
CP&L
SCE&G
Duke Energy

Public Service Commission of South Carolina
Annual Review of Base Rates for Fuel Costs
Summary of Fuel Rate Decisions
(rates reflected are ¢/kWh)

Approved Base Fuel Factor	1999	2000	2001	2002	2003	2004	2005
CP&L	1.122	1.265	1.517	1.471	1.471	1.471	2.791
SCE&G	1.337	1.330	1.579	1.722	1.678	1.821	2.256
Duke Energy	1.000	0.950	0.950	0.950	1.150	1.150	

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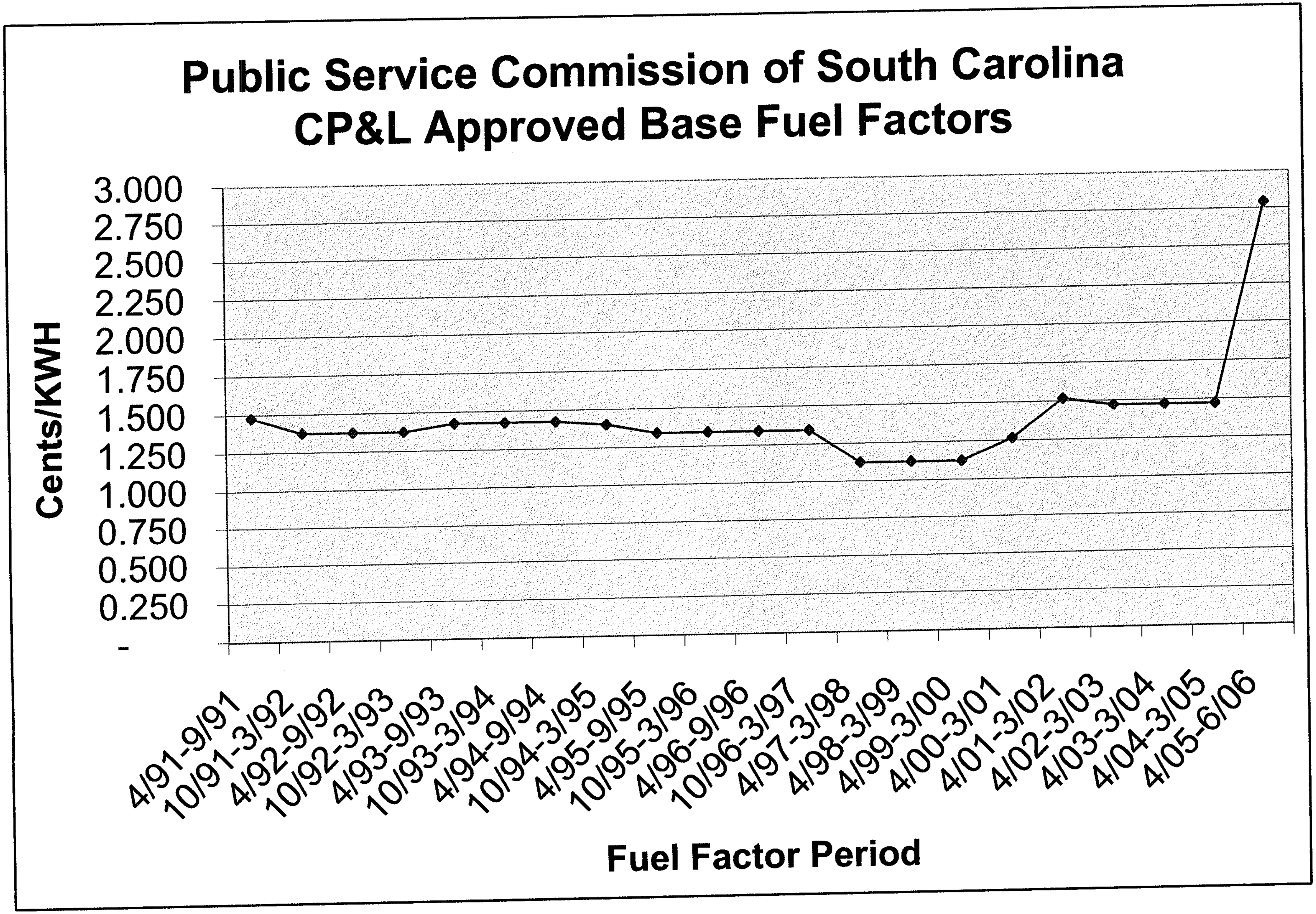
EXHIBIT NO. 2


Public Service Commission of South Carolina
CP&L Approved Base Fuel Factors
Cents/KWH
3.000
2.750
2.500
2.250
2.000
1.750
1.500
1.250
1.000
0.750
0.500
0.250
-
4/91-9/91
10/91-3/92
4/92-9/92
10/92-3/93
4/93-9/93
10/93-3/94
4/94-9/94
10/94-3/95
4/95-9/95
10/95-3/96
4/96-9/96
10/96-3/97
4/97-3/98
4/98-3/99
4/99-3/00
4/00-3/01
4/01-3/02
4/02-3/03
4/03-3/04
4/04-3/05
4/05-6/06
Fuel Factor Period

Public Service Commission of South Carolina
Annual Review of Base Rates for Fuel Costs
Summary of Fuel Rate Decisions
(rates reflected are ¢/kWh)

Approved Base Fuel Factor

	CP&L
4/91-9/91	1.475
10/91-3/92	1.375
4/92-9/92	1.375
10/92-3/93	1.375
4/93-9/93	1.425
10/93-3/94	1.425
4/94-9/94	1.425
10/94-3/95	1.400
4/95-9/95	1.340
10/95-3/96	1.340
4/96-9/96	1.340
10/96-3/97	1.340
4/97-3/98	1.122
4/98-3/99	1.122
4/99-3/00	1.122
4/00-3/01	1.265
4/01-3/02	1.517
4/02-3/03	1.471
4/03-3/04	1.471
4/04-3/05	1.471
4/05-6/06	2.791

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EXHIBIT NO. 3

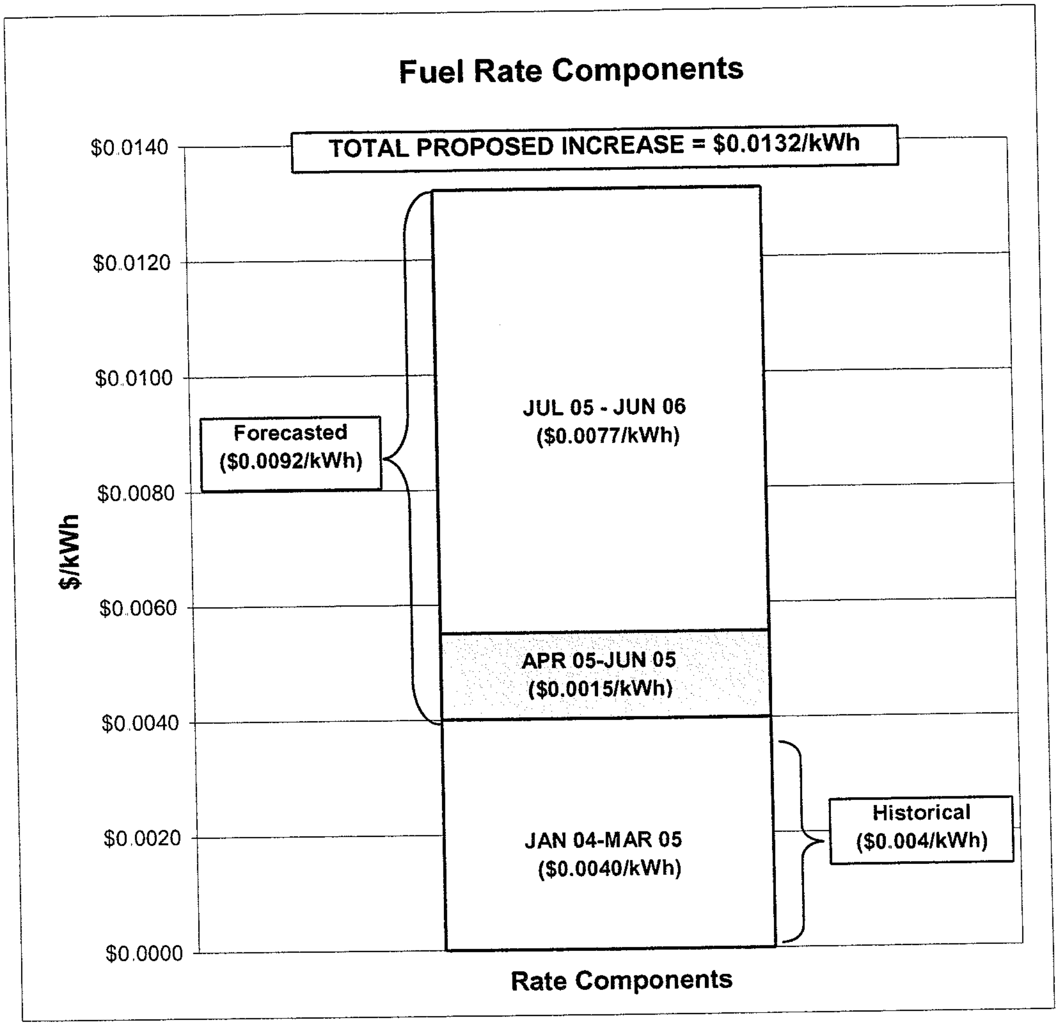
Fuel Rate Components
TOTAL PROPOSED INCREASE = $0.0132/kWh
$0.0140
$0.0120
$0.0100
$0.0080
$0.0060
$0.0040
$0.0020
$0.0000
$/kWh
Forecasted ($0.0092/kWh)
JUL 05 - JUN 06 ($0.0077/kWh)
APR 05-JUN 05 ($0.0015/kWh)
JAN 04-MAR 05 ($0.0040/kWh)
Historical ($0.004/kWh)
Rate Components

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EXHIBIT NO. 4

DOCKET NO. 2004-1-E
UTILITIES DEPARTMENT
EXHIBIT NO. 9

CAROLINA POWER & LIGHT COMPANY

d/b/a PROGRESS ENERGY CAROLINAS, INC.

HISTORY OF CUMULATIVE RECOVERY ACCOUNT

PERIOD ENDING	OVER (UNDER) $
March 1979 – Automatic Fuel Adjustment in Effect	
December 1979	1,104,730
September 1980	(12,000,131)
March 1981	(4,060,364)
August 1981	(12,113,832)
March 1982	(935,412)
September 1982	(6,881,796)
March 1983	(2,259,114)
September 1983	(3,264,694)
March 1984	109,270
September 1984	2,172,859
March 1985	(2,317,008)
September 1985	745,913
March 1986	1,972,280
September 1986	(696,805)
March 1987	2,408,354
September 1987	3,310,059
March 1988	(3,964,888)
September 1988	(5,737,541)
March 1989	(8,125,496)
September 1989	(5,875,641)
March 1990	(9,311,149)
September 1990	(658,614)
March 1991	1,403,023
September 1991	4,661,988
March 1992	5,201,112
September 1992	(6,712,920)
March 1993	(9,563,180)
September 1993	0*
March 1994	(1,010,684)
September 1994	1,975,939
March 1995	7,408,161
September 1995	2,011,489
December 1996	186,139
December 1997	(6,212,396)
December 1998	(14,334,022)
December 1999	(17,967,157)**
December 2000	(18,627,471)
December 2001	(9,906,921)
December 2002	(7,393,266)
December 2003	(6,038,891)

*Eliminated $14,011,263 per Commission Order No. 93-865
**Reduced by $6,500,000 per Commission Order No. 1999-324

ZARNIKAU

EXHIBIT NO. 5

OPEN ACCESS TRANSMISSION TARIFF
OF
CAROLINA POWER & LIGHT COMPANY

1.52 Power Purchaser:

The entity that is purchasing the capacity and energy to be transmitted under the Tariff.

1.53 Receiving Party:

The entity receiving the capacity and energy transmitted by the Transmission Provider to Point(s) of Delivery.

1.54 Regional Transmission Group (RTG):

A voluntary organization of transmission owners, transmission users and other entities approved by the Commission to efficiently coordinate transmission planning (and expansion), operation and use on a regional (and interregional) basis.

1.55 Reserved Capacity:

The maximum amount of capacity and energy that the Transmission Provider agrees to transmit for the Transmission Customer over the Transmission Provider's Transmission System between the Point(s) of Receipt and the Point(s) of Delivery under Part II of the Tariff or from Network Resources to Points of Delivery under Part IV of the Tariff. Reserved Capacity shall be expressed in terms of whole megawatts on a sixty (60) minute interval (commencing on the clock hour) basis.

1.56 SERC:

The Southeastern Electric Reliability Council, a regional reliability council of NERC.

1.57 Service Agreement:

The initial agreement and any amendments or supplements thereto entered into by the Transmission Customer and the Transmission Provider for service under the Tariff.

SCHEDULE 7

Long-Term Firm and Short-Term Firm Point-To-Point Transmission Service

The Transmission Customer shall compensate the Transmission Provider for Reserved Capacity at the sum of the applicable charges for a zone set forth below:

Charges:

The charges for Long-Term Firm and Short-Term Firm Point-To-Point Transmission Service shall be based on the Zone in which the energy being transmitted is consumed or, if the energy is transmitted to an interface with another transmission provider, the Zone in which transmission service is last provided by the Transmission Provider. The applicable zonal charges are set out below.

A. CP&L Zone

A.7.1 **Annual Period**: one-twelfth of the annual demand charge of $10,800/MW of Reserved Capacity per year.

A.7.2 **Monthly Period:** $900/MW of Reserved Capacity per month.

A.7.3 **Weekly Period:** $208/MW of Reserved Capacity per week.

A.7.4 **Daily Period:** $42/MW of Reserved Capacity per On-Peak Day and $30/MW of Reserved Capacity per Off-Peak Day. The total demand charge in any Weekly Period, pursuant to a reservation for Daily Period delivery, shall not exceed the rate specified in section A.7.3 above times the highest amount in kilowatts of Reserved Capacity in any Daily Period during such Weekly Period.

A.7.5 **Discounts**: Three principal requirements apply to discounts for transmission service as follows: (1) any offer of a discount made by the Transmission Provider must be announced to all Eligible Customers solely by posting on the OASIS, (2) any customer-initiated requests for discounts (including requests for use by one's wholesale merchant or affiliate's use) must occur solely by posting on the OASIS, and (3) once a discount is negotiated, details must be immediately posted on the OASIS. For any discount agreed upon for service on a path from point(s) of receipt to point(s) of delivery, the Transmission Provider must offer the same discount transmission service rate for the same time period to all Eligible Customers on all unconstrained transmission paths that go to the same point(s) of delivery on the Transmission System.

A.7.6 **Unauthorized Use:** For each day that the Transmission Customer's use of the Transmission System during any hour of that day exceeds the amount of the Transmission Customer's Reserved Capacity, the Transmission Customer shall pay the Transmission Provider a penalty charge based on a rate equal to 150% of the daily rate for transmission service provided multiplied by the amount of the maximum excess usage in any hour of the day of the Transmission Customer's reservation. Losses delivered to the CP&L Zone by the Transmission Customer will not be included in the Transmission Customer's usage for determination of the charge set out herein.

A.7.7 **Additional Charges:** The Transmission Customer will compensate CP&L for any facility additions or redispatch costs in accordance with Sections 13.5, 27 and 45.2 of the Tariff. Redispatch costs will be computed in accordance with the methodology outlined in Attachment J.

A.7.8 **Losses:** For purposes of billing, the Reserved Capacity to be applied under Sections A.7.1 through A.7.4 of this schedule shall not include losses purchased or provided by the Transmission Customer.

B. FPC Zone

B.7.1 **Monthly Period:** $1,016/MW month.

B.7.2 **Weekly Period:** $234.54/MW week.

B.7.3 **Daily Period:** The charge for Daily Period delivery for On-Peak Days shall be $46.91/MW day, and the charge for Daily Period delivery for Off-Peak Days shall be $33.42/MW day. The total demand charge in any Weekly Period, pursuant to a reservation for Daily Period delivery, shall not exceed the Weekly Period rate times the highest amount in kilowatts of Reserved Capacity in any Daily Period during such Weekly Period.

NOTE: All quantities used in calculating the Transmission Customer's Reserved Capacity shall be established at the transmission system input level, *i.e.*, shall include the transmission capacity amount associated with any losses.

B.7.4 **Discounts**: Three principal requirements apply to discounts for transmission service as follows: (1) any offer of a discount made by the Transmission Provider must be announced to all Eligible Customers solely by posting on the OASIS, (2) any customer-initiated requests for discounts (including requests for use by one's wholesale merchant or affiliate's use) must occur solely by posting on the OASIS, and (3) once a discount is negotiated, details must be immediately posted on the OASIS. For any discount agreed upon for service on a path from point(s) of receipt to point(s) of delivery, the Transmission Provider must offer the same discount transmission service rate for the same time period to all Eligible Customers on all unconstrained transmission paths that go to the same point(s) of delivery on the Transmission System.

B.7.5 **Unauthorized Use:** A Transmission Customer that exceeds its Reserved Capacity shall pay a charge equal to the amount of the capacity delivered in excess of the Reserved

Capacity multiplied by 150% of the applicable charge for the lesser of the term of that transaction or one month.

B.7.6 **Regulatory Assessment:** The portion of the charge by FERC pursuant to 18 C.F.R. § 382.201 related to service under this Tariff. The Regulatory Assessment shall be allocated to the Transmission Customer on an annual basis in the year following the year in which transmission service is rendered, based on the megawatt-hours of service provided to the Transmission Customer or based upon such other method as these fees are assessed by FERC.

SCHEDULE 8

Non-Firm Point-To-Point Transmission Service

The Transmission Customer shall compensate the Transmission Provider for Non-Firm Point-To-Point Transmission Service up to the sum of the applicable charges for a zone set forth below:

Charges:

The charge for Non-Firm Point-To-Point Transmission Service shall be based on the Zone in which the energy being transmitted is consumed or, if the energy is transmitted to an interface with another transmission provider, the Zone in which transmission service is last provided by the Transmission Provider. The applicable zonal charges are set out below.

A. CP&L Zone

A.8.1 **Monthly Period:** $900/MW of Reserved Capacity per month.

A.8.2 **Weekly Period:** $208/MW of Reserved Capacity per week.

A.8.3 **Daily Period:** $42/MW of Reserved Capacity per On-Peak Day and $30/MW of Reserved Capacity per Off-Peak Day. The total demand charge in any Weekly Period, pursuant to a reservation for Daily Period delivery, shall not exceed the rate specified in Section A.8.2 above times the highest amount in kilowatts of Reserved Capacity in any Daily Period during such Weekly Period.

A.8.4 **Hourly Period:** The basic charge shall be that agreed upon by the Parties at the time this service is reserved and in no event shall exceed $2.60/MWH per On-Peak Hour and $1.23/MWH per Off-Peak Hour. The total demand charge in any Daily Period, pursuant to a reservation for Hourly Period delivery, shall not exceed the Daily Period rate above times the highest amount in kilowatts of Reserved Capacity in any Hourly Period during such Daily Period. In addition, the total demand charge in any Weekly Period, pursuant to a reservation for Hourly Period or Daily Period delivery, shall not exceed the Weekly Period rate times the highest amount in kilowatts of Reserved Capacity in any Hourly Period during such Weekly Period.

A.8.5 **Discounts**: Three principal requirements apply to discounts for transmission service as follows: (1) any offer of a discount made by the Transmission Provider must be announced to all Eligible Customers solely by posting on the OASIS, (2) any customer-initiated requests for discounts (including requests for use by one's wholesale merchant or affiliate's use) must occur solely by posting on the OASIS, and (3) once a discount is negotiated, details must be immediately posted on the OASIS. For any discount, agreed upon for service on a path, from point(s) of receipt to point(s) of delivery, the Transmission Provider must offer the same discount transmission service rate for the same time period to all Eligible Customers on all unconstrained transmission paths that go to the same point(s) of delivery on the Transmission System.

A.8.6 **Unauthorized Use:** For each hour that the Transmission Customer's use of the Transmission System exceeds the amount of the Transmission Customer's Reserved Capacity, the Transmission Customer shall pay the Transmission Provider a penalty charge based on a rate equal to 150% of the hourly rate for the transmission service provided multiplied by the amount of the maximum excess usage in any hour of the day of the Transmission Customer's reservation. Losses delivered to the CP&L Zone by the Transmission Customer will not be included in the Transmission Customer's usage for determination of the charge set out herein.

A.8.7 **Additional Charges:** The Transmission Customer will compensate CP&L for any facility additions or redispatch costs in accordance with Sections 13.5, 27 and 45.2 of the Tariff.

Redispatch costs will be computed in accordance with the methodology outlined in Attachment J.

A.8.8 **Losses:** For purposes of billing, the Reserved Capacity to be applied under Sections A.8.1 through A.8.4 of this schedule shall not include losses purchased or provided by the Transmission Customer.

B. FPC Zone

B.8.1 **Monthly Period:** $834/MW month.

B.8.2 **Weekly Period:** $192.45/MW week.

B.8.3 **Daily Period:** The maximum charge for Daily Period delivery for On-Peak Days shall be $38.49/MW day and the maximum charge for Daily Period delivery for Off-Peak Days shall be $27.42/MW day. The total demand charge in any Weekly Period, pursuant to a reservation for Daily Period delivery, shall not exceed the rate specified in Section B.8.2 above times the highest amount in kilowatts of Reserved Capacity in any Daily Period during such Weekly Period.

B.8.4 **Hourly Period:** The maximum charge for Hourly Period service for On-Peak Hours shall be $2.41/MW hour and the maximum charge for Hourly Period service for Off-Peak Hours shall be $1.14/MW hour. The total demand charge in any Daily Period, pursuant to a reservation for Hourly Period delivery, shall not exceed the Daily Period rate above times the highest amount in kilowatts of Reserved Capacity in any Hourly Period during such Daily Period. In addition, the total demand charge in any Weekly Period, pursuant to a reservation for Hourly Period or Daily Period delivery, shall not exceed the Weekly Period rate times the highest amount in kilowatts of Reserved Capacity in any Hourly Period during such Weekly Period.

NOTE: All quantities used in calculating the Transmission Customer's Reserved Capacity shall be established at the transmission system input level, *i.e.*, shall include the transmission capacity amount associated with any losses.

B.8.5 **Discounts**: Three principal requirements apply to discounts for transmission service as follows: (1) any offer of a discount made by the Transmission Provider must be announced to all Eligible Customers solely by posting on the OASIS, (2) any customer-initiated requests for discounts (including requests for use by one's wholesale merchant or affiliate's use) must occur solely by posting on the OASIS, and (3) once a discount is negotiated, details must be immediately posted on the OASIS. For any discount, agreed upon for service on a path, from point(s) of receipt to point(s) of delivery, the Transmission Provider must offer the same discount transmission service rate for the same time period to all Eligible Customers on all unconstrained transmission paths that go to the same point(s) of delivery on the Transmission System.

B.8.6 **Unauthorized Use:** A Transmission Customer that exceeds its Reserved Capacity shall pay a charge equal to the amount of the capacity delivered in excess of the Reserved Capacity multiplied by 150% of the applicable charge for the lesser of the term of that transaction or one month.

B.8.7 **Regulatory Assessment:** The Transmission Customer shall pay a portion of the charge by FERC pursuant to 18 C.F.R. § 382.201 related to service under this Tariff. The Regulatory Assessment shall be allocated to the Transmission Customer on an annual basis in the year following the year in which transmission service is rendered, based on the megawatt-hours of service provided to the Transmission Customer or based upon such other method as these fees are assessed by FERC.

SCHEDULE 11

Long-Term and Short-Term Network Contract Demand Transmission Service

The Transmission Customer shall compensate the Transmission Provider for Reserved Capacity at the sum of the applicable charges for a zone set forth below.

Charges:

The charge for Network Contract Demand Transmission Service shall be based on the Zone in which the energy being transmitted is consumed or, if the energy is transmitted to an interface with another transmission provider, the Zone in which transmission service is last provided by the Transmission Provider. The applicable zonal charges are set out below.

A. CP&L Zone

A.11.1 **Annual Period**: one-twelfth of the annual demand charge of $10,800/MW of Reserved Capacity per month.

A.11.2 **Monthly Period:** $900/MW of Reserved Capacity per month.

A.11.3 **Weekly Period:** $208/MW of Reserved Capacity per week.

A.11.4 **Daily Period:** $42/MW of Reserved Capacity per On-Peak Day and $30/MW of Reserved Capacity per Off-Peak Day. The total demand charge in any Weekly Period, pursuant to a reservation for Daily Period delivery, shall not exceed the rate specified in section A.11.3 times the highest amount in kilowatts of Reserved Capacity in any Daily Period during such Weekly Period.

A.11.5 **Discounts**: Three principal requirements apply to discounts for transmission service as follows: (1) any offer of a discount made by the Transmission Provider must be announced to all Eligible Customers solely by posting on the OASIS, (2) any customer-initiated requests for discounts (including requests for use by one's wholesale merchant or affiliate's use) must occur solely by posting on the OASIS, and (3) once a discount is negotiated, details must be immediately posted on the OASIS. For any discount agreed upon for service on a path from point(s) of receipt to point(s) of delivery, the Transmission Provider must offer the same discount transmission service rate for the same time period to all Eligible Customers on all unconstrained transmission paths that go to the same point(s) of delivery on the Transmission System.

A.11.6 **Unauthorized Use:** For each day that the Transmission Customer's use of the Transmission System during any hour of that day exceeds the amount of the Transmission Customer's Reserved Capacity, the Transmission Customer shall pay the Transmission Provider a penalty charge based on a rate equal to 150% of the daily rate for firm point-to-point transmission service provided multiplied by the amount of the maximum excess usage in any hour in the day of the Transmission Customer's reservation. Losses delivered to the CP&L Zone by the Transmission Customer will not be included in the Transmission Customer's usage for determination of the charge set out herein.

A.11.7 **Additional Charges:** The Transmission Customer will compensate CP&L for any facility additions or redispatch costs in accordance with Sections 13.5, 27 and 45.2 of the Tariff. Redispatch costs will be computed in accordance with the methodology outlined in Attachment J.

A.11.8 **Losses:** For purposes of billing, the Reserved Capacity to be applied under Sections A.11.1 through A.11.4 of this schedule shall not include losses purchased or provided by the Transmission Customer.

B. FPC Zone

B.11.1 **Monthly Period:** $1,016/MW month.

B.11.2 **Weekly Period:** $234.54/MW week.

B.11.3 **Daily Period:** The charge for Daily Period delivery for On-Peak Days shall be $46.91/MW day and the charge for Daily Period delivery for Off-Peak Days shall be $33.42/MW day. The total demand charge in any Weekly Period, pursuant to a reservation for Daily Period delivery, shall not exceed the Weekly Period rate times the highest amount in kilowatts of Reserved Capacity in any Daily Period during such Weekly Period.

NOTE: All quantities used in calculating the Transmission Customer's Reserved Capacity shall be established at the transmission system input level, *i.e.*, shall include the transmission capacity amount associated with any losses.

B.11.4 **Unauthorized Use:** A Transmission Customer that exceeds its Reserved Capacity shall pay a charge equal to the amount of the capacity delivered in excess of the Reserved Capacity multiplied by 150% of the applicable charge for the lesser of the term of that transaction or one month.

B.11.5 **Regulatory Assessment:** The Transmission Customer shall pay a portion of the charge by FERC pursuant to 18 C.F.R. § 382.201 related to service under this Tariff. The Regulatory Assessment Expense shall be allocated to the Transmission Customer on an annual basis in the year following the year in which transmission service is rendered based on the megawatt-hours of service provided to the Transmission Customer or based upon such other method as these fees are assessed by FERC.

ZARNIKAU

EXHIBIT NO. 6

LARGE GENERAL SERVICE
(EXPERIMENTAL - REAL TIME PRICING)
SCHEDULE LGS-RTP-6

AVAILABILITY

This Schedule is available for electric service on an experimental basis to a maximum of fifteen (15) nonresidential customers with a Contract Demand that equals or exceeds 1,000 kW.

This Schedule is not available: (1) for short-term or temporary service; (2) for electric service in conjunction with Curtailable Load Rider No. 58, Incremental Power Service Rider IPS, Dispatched Power Rider No. 68, Standby and Supplementary Service Rider No. 7, Customer Generation Service Rider No. 55, and Economic Development Rider ED; (3) to a customer who had discontinued receiving service under this Schedule, or its predecessor, during the previous 12 months; (4) for any new customer with a Contract Demand in excess of 50,000 kW; or (5) for service rendered on and after December 31, 2007. Power delivered under this Schedule shall not be used for resale, or as a substitute for power contracted for or which may be contracted for under any other schedule of Company, except at the option of Company, under special terms and conditions expressed in writing in the contract with Customer. Customer shall be required to furnish and maintain a communication link and equipment suitable to support remote reading of Company's meter serving Customer and to support daily receipt of the Hourly Real Time Pricing (RTP) Rates.

APPLICABILITY

This Schedule is applicable to all electric service of the same available type supplied to Customer's premises at one point of delivery through one meter.

TYPE OF SERVICE

The types of service to which this Schedule is applicable are alternating current, 60 hertz, three-phase 3 or 4 wires, at Company's standard voltages of 480 volts or higher. When Customer desires two or more types of service, which types can be supplied from a three-phase 4 wire type, without voltage transformation, only the type of service necessary for Customer's requirements will be supplied under this Schedule.

CONTRACT DEMAND

The Contract Demand shall be the kW of demand specified in the Service Agreement.

CUSTOMER BASELINE LOAD (CBL)

Company shall establish a Customer Baseline Load (CBL), expressed in kilowatt-hours, using one complete year of Customer-specific hourly load data that, in Company's opinion, represents Customer's electricity consumption pattern and is typical of Customer's operation for billing under the otherwise applicable tariffs and from which to measure changes in consumption for billing pursuant to this Schedule. For situations in which hourly load data are not available, a CBL will be constructed by Company using load shapes of customers with similar usage patterns and from relevant information provided by Customer and verified by Company. Establishment of a CBL is a precondition for use of this Schedule.

CBL DETERMINATION

The CBL shall be adjusted at Company's sole discretion to reflect: (1) installation of permanent energy efficiency measures; (2) permanent removal or addition of Customer's equipment; (3) one-time extraordinary events such as natural disasters; (4) annual plant shutdowns or other random variations in the load patterns; and (5) other changes in usage. After the initial CBL is established, it shall only be subject to a downward adjustment at Customer's request by providing 30 days advance written notice of a permanent reduction of electrical load due to the installation of demonstrable energy efficiency measures or removal of Customer's equipment. Such downward adjustment is subject to Company's concurrence.

CBL CALENDAR MAPPING

To provide Customer with the appropriate CBL for the RTP Service Year, the hourly consumptions established by the CBL shall be calendar-mapped to the corresponding day of the RTP Service Year. Calendar-mapping is a day-matching method to ensure that Mondays are matched to Mondays, holidays to holidays, etc.

The CBL shall be established by first identifying holidays and then grouping the remaining days, i.e., Mondays, Tuesdays, etc, and averaging over the calendar month to result in hourly consumption for a typical week in each calendar month. The CBL result shall then be adjusted for each calendar month to reflect annual plant shutdowns, holidays, or other known work stoppages during the next RTP Service Year. Calendar-mapping is performed prior to each annual renewal of service under this Schedule after adjustments, if any, are made to the CBL.

MONTHLY RATE

The monthly rate shall consist of the following charges:

I. RTP Administrative Charge:

$500.00

II. RTP Base Charge:

RTP Base Charge = Monthly Bill for the hourly CBL consumption of the current billing month pursuant to the conventional LGS Class tariffs under which Customer either previously received service or would have elected to receive service prior to electing this Schedule.

III. RTP Hourly Energy Charge Adjustment:

RTP Hourly Energy Charge = $\sum$ {Hourly RTP Rate X (Hourly Consumption - CBL Consumption)}

where:

$\sum$ = The summation of the RTP charges and credits for each hour of the current billing month.

The Hourly RTP Rate shall be determined based upon the following formula:

Hourly RTP Rate = (MENERGY + CAP + ADDER) X (1 + TAXES)

where:

MENERGY = Marginal Energy Cost per kilowatt-hour including marginal fuel, variable operating and maintenance expenses, and delivery losses

CAP	=	Tiered Capacity Charge per kilowatt-hour applicable whenever the day-ahead forecast of the ratio of hourly available generation to hourly demand is equal or less than 1.15
ADDER	=	β X (Class Rate-Hourly Marginal Cost), but not less than zero.

where:

β	=	a fixed value equal to 0.20
Class Rate	=	the prior calendar year average rate per kilowatt-hour under the conventional tariffs applicable to the LGS class, as updated annually effective with the February billing
Hourly Marginal Cost	=	the sum of the specific hour's kilowatt-hour price for MENERGY and CAP, all as defined above
TAXES	=	South Carolina Gross Receipts Tax (currently 0.3%)

IV. Facilities Demand Charge:

per kW of Facilities Demand for service provided from:

Transmission System (voltage of 69 kV or higher) without transformation	\$1.74/kW
Transmission System (voltage of 69 kV or higher) with one transformation	\$2.17/kW
Distribution System (voltage below 69 kV) without transformation	\$2.34/kW
Distribution System (voltage below 69 kV) with one transformation	\$2.66/kW

The kW of Facilities Demand shall be the greater of (1) the Contract Demand or (2) the maximum demand registered or recorded by Company's meter during a 15-minute interval in the current billing month, in excess of the maximum demand included in the CBL applicable to the current billing month. The Facilities Demand shall include any Standby Service kW, when applicable.

PROVISION OF STANDBY SERVICE

If service is received under a standby service tariff prior to service under this Schedule, the use of standby service shall be excluded from initial determination and update of the CBL. The RTP Base Charge, as set forth in the Monthly Rate provision above, shall include billing of Supplementary Service but shall not include any charges related to reservation or use of Standby Service. If Standby Service is provided, Customer must contract to receive service under Standby Service Rider No. SS, or its successor. However, notwithstanding any provisions of Rider SS, the Demand Delivery Charge, Daily Demand Charge and Energy Charge shall not be applicable for billing purposes under this Schedule. Any use of Standby Service shall be billed pursuant to the RTP Hourly Energy Charge provisions of this Schedule.

POWER FACTOR ADJUSTMENT

When the power factor in the current billing month is less than 85%, the monthly bill will be increased by a sum equal to \$0.30 multiplied by the difference between the maximum reactive kilovolt-amperes (kVAr) registered by a demand meter suitable for measuring the demand used during a 15-minute interval and 62% of the maximum kW demand registered in the current billing month.

CUSTOMER RATE NOTIFICATION

Company will notify Customer of the hourly prices via electronic mail, or other method of communications acceptable to Company, by 4 p.m. of the preceding business day. Prices for Saturday, Sunday and Monday will generally be available on the preceding Friday. For a recognized holiday and the day following the holiday, prices will be available the preceding Company business day. Whenever prices are provided in excess of a day ahead and updated projections would result in significantly different prices, Company reserves the right to issue revised prices provided such prices are conveyed no later than 4 p.m. on the preceding calendar day.

Company is not responsible nor liable for Customer's failure to receive and act upon the hourly prices. If Customer does not receive these prices, it is Customer's responsibility to inform Company so that future prices may be supplied.

SALES AND FRANCHISE TAX OR PAYMENT IN LIEU THEREOF

To the above charges will be added any applicable South Carolina sales tax, and for those customers within any municipal or other local governmental jurisdiction, an appropriate amount to reflect any franchise fee, business license tax, or similar percentage fee or tax, or charge in lieu thereof imposed by such entity.

PAYMENTS

Bills are due when rendered and are payable within 15 days from the date of the bill. If any bill is not so paid, the Company has the right to suspend service in accordance with its Service Regulations. In addition, any bill not paid on or before the expiration of twenty-five (25) days from the date of the bill is subject to an additional charge of 1% per month as provided in Rule 103-339(3) of the Rules and Regulations of the South Carolina Public Service Commission.

CONTRACT PERIOD

The Contract Term shall be for one year and will be automatically renewed annually unless terminated by either party by giving not less than thirty (30) days written notice of termination. In the event the Contract Period extends beyond December 31, 2007, the Contract Period shall instead be a period ending December 31, 2007. During the initial 12 months of service under this Schedule, the Contract Period may be terminated, at Company's option, when continued service under this Schedule will result in a demonstrable economic hardship for the Customer.

GENERAL

Service rendered under this Schedule is subject to the provisions of the Service Regulations and any changes therein, substitutions therefor, or additions thereto lawfully made.

Company makes no representation regarding the benefits of Customer subscribing to this Schedule. Customer, in its sole discretion, shall determine the feasibility and benefits of Customer subscribing to this Schedule.

Supersedes Schedule LGS-RTP-4
Effective for service rendered on and after October 28, 2004
SCPSC Docket No. 97-057-E, Order No. 2004-545

Carolina Power & Light Company
d/b/a Progress Energy Carolinas, Inc.
(North Carolina Only)

LARGE GENERAL SERVICE
(EXPERIMENTAL - REAL TIME PRICING)
SCHEDULE LGS-RTP-5B

AVAILABILITY

This Schedule is available for electric service on an experimental basis to a maximum of eighty-five (85) nonresidential Customer accounts with a Contract Demand that equals or exceeds 1,000 kW.

This Schedule is not available: (1) for short-term or temporary service; (2) for electric service in conjunction with Incremental Power Service Rider IPS or Dispatched Power Rider No. 68; (3) for electric service in conjunction with Economic Development Rider ED and Curtailable Load Riders No. 58 and CL, except as provided for in the RTP Base Charge; (4) to a customer who had discontinued receiving service under this Schedule, or its predecessor, during the experiment; (5) for any new Customer with a Contract Demand in excess of 50,000 kW; or (6) for service rendered on and after December 31, 2009.

Power delivered under this Schedule shall not be used for resale, or as a substitute for power contracted for or which may be contracted for under any other schedule of Company, except at the option of Company, under special terms and conditions expressed in writing in the contract with Customer. Customer shall be required to furnish and maintain a communication link and equipment suitable to support remote reading of Company's meter serving Customer and to support daily receipt of the Hourly Real Time Pricing (RTP) rates.

APPLICABILITY

This Schedule is applicable to all electric service of the same available type supplied to Customer's premises at one point of delivery through one meter.

TYPE OF SERVICE

The types of service to which this Schedule is applicable are alternating current, 60 hertz, three-phase 3 or 4 wires, at Company's standard voltages of 480 volts or higher. When Customer desires two or more types of service, which types can be supplied from a three-phase 4 wire type, without voltage transformation, only the type of service necessary for Customer's requirements will be supplied under this Schedule.

CONTRACT DEMAND

The Contract Demand shall be the kW of demand specified in the Service Agreement.

CUSTOMER BASELINE LOAD (CBL)

Company shall establish a Customer Baseline Load (CBL), expressed in kilowatt-hours, using one complete year of Customer-specific hourly load data that, in Company's opinion, represents Customer's electricity consumption pattern and is typical of Customer's operation for billing under the otherwise applicable tariffs and from which to measure changes in consumption for billing pursuant to this Schedule. For situations in which hourly load data are not available, a CBL will be constructed by Company using load shapes of Customers with similar usage patterns and from relevant information provided by Customer and verified by Company. The initial CBL shall consider verifiable changes in Customer's operation such as (1) installation of permanent energy efficiency measures; (2) permanent removal or addition of Customer's equipment; (3) one-time extraordinary events such as natural disasters; (4) annual plant shutdowns or other random variations in the load patterns; and (5) other on-going changes in demand. The CBL for new customers will be calculated in the same manner as the CBL for existing Customers. Establishment of a CBL is a precondition for use of this Schedule.

SUBSEQUENT CBL ADJUSTMENT

After the initial CBL is established, it shall only be subject to an adjustment at Customer's request by providing 30-days advance written notice. Any downward adjustment is subject to Company's concurrence and will be consistent with the principles of initial CBL establishment.

CBL CALENDAR MAPPING

To provide Customer with the appropriate CBL for the RTP Service Year, the hourly consumptions established by the CBL shall be calendar-mapped to the corresponding day of the RTP Service Year. Calendar-mapping is a day-matching method to ensure that Mondays are matched to Mondays, holidays to holidays, etc.

The CBL shall be established by first identifying holidays and then grouping the remaining days (i.e., Mondays, Tuesdays, etc.) and averaging over the calendar month to result in hourly consumption for a typical week in each calendar month. The CBL result shall then be adjusted for each calendar month to reflect annual plant shutdowns, holidays, or other known work stoppages during the next RTP Service Year. Calendar-mapping is performed prior to each annual renewal of service under this Schedule after adjustments, if any, are made to the CBL.

MONTHLY RATE

The monthly rate shall consist of the following charges:

I. RTP Administrative Charge:

$500.00

II. RTP Base Charge:

RTP Base Charge = Monthly Bill for the CBL consumption and monthly billing demand of the current billing month pursuant to the conventional LGS Class tariffs under which Customer either previously received service or would have elected to receive service prior to electing this Schedule. When the conventional tariffs include Economic Development Rider ED or Curtailable Load Rider No. 58 or CL, the provisions of these Riders shall only apply to the CBL usage.

III. RTP Hourly Energy Charge Adjustment:

RTP Hourly Energy Charge = Σ{Hourly RTP Rate X (Hourly Consumption - CBL Consumption)}

where:
Σ = The summation of the RTP charges and credits for each hour of the current billing month.

The Hourly RTP Rate shall be determined based upon the following formula:

Hourly RTP Rate = (MENERGY + CAP + ADDER) X (1 + TAXES)

where:
MENERGY = Marginal Energy Cost per kilowatt-hour including marginal fuel, variable operating and maintenance expenses, and delivery losses

CAP	=	Tiered Capacity Charge per kilowatt-hour applicable whenever the day-ahead forecast of the ratio of hourly available generation to hourly demand is equal or less than 1.15
ADDER	=	β X (Class Rate-Hourly Marginal Cost), but not less than zero

where:

β	=	a fixed value equal to 0.20
Class Rate	=	the prior calendar year average rate per kilowatt-hour under the conventional tariffs applicable to the LGS class, as updated annually effective with the February billing
Hourly Marginal Cost	=	the sum of the specific hour's kilowatt-hour price for MENERGY and CAP, all as defined above
TAXES	=	North Carolina Gross Receipts Tax (currently 3.22%)

IV. Facilities Demand Charge:

per kW of Facilities Demand for service provided from:

Transmission System (voltage of 69 kV or higher) without transformation	$1.74/kW
Transmission System (voltage of 69 kV or higher) with one transformation	$2.17/kW
Distribution System (voltage below 69 kV) without transformation	$2.34/kW
Distribution System (voltage below 69 kV) with one transformation	$2.66/kW

The kW of Facilities Demand shall be the greater of (1) the Contract Demand or (2) the maximum demand registered or recorded by Company's meter during a 15-minute interval in the current billing month, in excess of the maximum 15-minute billing demand included in the CBL applicable to the current billing month. The Contract Demand used to determine the Facilities Demand shall exclude any Standby Service kW, when applicable.

PROVISION OF STANDBY SERVICE

If service is received under a standby or back-up service tariff prior to service under this Schedule, the use of standby service shall be excluded from initial determination of the CBL. The RTP Base Charge, as set forth in the Monthly Rate provision above, shall include billing of Supplementary Service but shall not include charges related to use of Standby Service. The Monthly Rate provisions of the applicable standby or back-up service tariff shall be calculated assuming no standby or back-up service was used with any actual use of Standby Service being billed pursuant to the RTP Hourly Energy Charge provisions of this Schedule. All other provisions of the applicable standby or back-up service tariff apply.

POWER FACTOR ADJUSTMENT

When the power factor in the current billing month is less than 85%, the monthly bill will be increased by a sum equal to $0.40 multiplied by the difference between the maximum reactive kilovolt-amperes (kVAr) registered by a demand meter suitable for measuring the demand used during a 15-minute interval and 62% of the maximum kW demand registered in the current billing month.

CUSTOMER RATE NOTIFICATION

Company will notify Customer of the hourly prices via electronic mail, or other method of communications acceptable to Company, by 4 p.m. of the preceding business day. Prices for Saturday, Sunday, and Monday will generally be available on the preceding Friday. For a recognized holiday and the day following the holiday, prices will be available the preceding Company business day. Whenever prices are provided in excess of a day ahead and updated projections would result in significantly different prices, Company reserves the right to issue revised prices provided such prices are conveyed no later than 4 p.m. on the preceding calendar day.

Company is not responsible nor liable for Customer's failure to receive and act upon the hourly prices. If Customer does not receive these prices, it is Customer's responsibility to inform Company so that future prices may be supplied.

SALES TAX

To the above charges will be added any applicable North Carolina Sales Tax.

PAYMENTS

Bills are due when rendered and are payable within 15 days from the date of the bill. If any bill is not so paid, Company has the right to suspend service in accordance with its Service Regulations. In addition, any bill not paid on or before the expiration of twenty-five (25) days from the date of the bill is subject to an additional charge of 1% per month as provided in Rule R12-9 of the Rules and Regulations of the North Carolina Utilities Commission.

CONTRACT PERIOD

The Contract Period shall be monthly and will be automatically renewed unless terminated by either party by giving not less than thirty (30) days written notice of termination. In the event the Contract Period extends beyond December 31, 2009, the Contract Period shall instead be a period ending December 31, 2009.

GENERAL

Service rendered under this Schedule is subject to the provisions of the Service Regulations and any changes therein, substitutions therefor, or additions thereto lawfully made.

Company makes no representation regarding the benefits of Customer subscribing to this Schedule. Customer, in its sole discretion, shall determine the feasibility and benefits of Customer subscribing to this Schedule.

Supersedes Schedule LGS-RTP-5A
Effective for service rendered on and after October 1, 2003
NCUC Docket No. E-2, Sub 704

ZARNIKAU

EXHIBIT NO. 7

PROGRESS ENERGY CAROLINAS, INC.

Request:

Referring to PEC's treatment of its experimental real-time pricing rate in which the RTP Hourly Energy Charge is determined by hourly marginal costs (whether in NC or SC):

(a) For the period under review, please explain, support, and provide all evidence or documentation for how PEC has treated sales and fuel costs for its experimental real-time pricing rate.
(b) Indicate the RTP Hourly Energy Charge by hour (and the hourly marginal cost used as a basis for that charge, if different) for each hour during the historical period and the number of RTP kWh sold in each such hour;
(c) Please provide a copy of each real-time pricing tariff and any related documents explaining the operation of the real time pricing program.

Response:

a) Energy sales and fuel revenues under the Large General Service Experimental Real Time Pricing Schedule are recorded on the Company's books in the same manner of other general service tariffs. The reported fuel revenue reflects the fuel factor approved by the Commission.
b) The RTP hourly rate and the marginal energy cost used in its development are deemed to be confidential and will therefore be made available for review in PEC's offices. NC and SC hourly energy sales under Schedule LGS-RTP are not retained but are available on a billing month basis as follows:

Billing Month	RTP Hourly Sales (kWh)
Jan-04	45,968,718
Feb-04	77,504,006
Mar-04	60,212,235
Apr-04	68,351,985
May-04	87,513,592
Jun-04	88,173,809
Jul-04	91,362,119
Aug-04	82,481,453
Sep-04	87,934,762
Oct-04	72,187,109
Nov-04	75,810,267
Dec-04	73,640,070
Jan-05	71,760,119
Feb-05	80,890,654
Mar-05	78,910,861

RTP Hourly Sales exclude sales made under the Customer Baseline Load and only reflect net sales under the Schedule that are subject to RTP hourly rates.

c) A copy of the Large General Service (Experimental – Real Time Pricing) Schedule LGS-RTP is available at Progress Energy's external website under "electric rates" at the following link:

http://progress-energy.com/aboutenergy/rates/index.asp

The LGS-RTP Schedule is available in both the North Carolina and South Carolina jurisdiction.

ZARNIKAU

EXHIBIT NO. 8

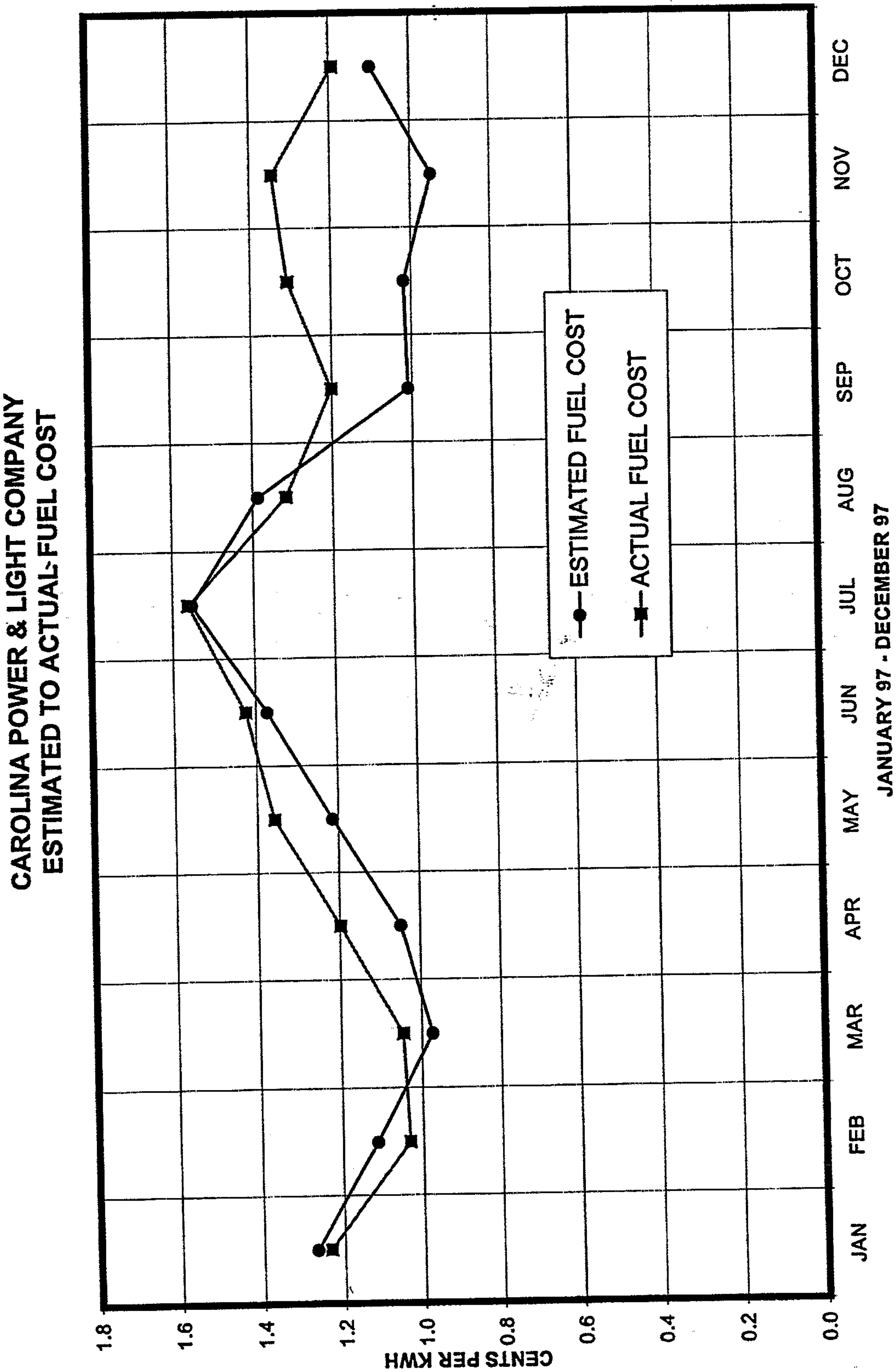
DOCKET NO. 98-001-E
UTILITIES DEPARTMENT
EXHIBIT NO. 6

CAROLINA POWER & LIGHT COMPANY

SOUTH CAROLINA RETAIL COMPARISON OF ESTIMATED TO ACTUAL FUEL COST FOR 1997

	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC
[1] ORIGINAL PROJECTION	1.267	1.113	0.973	1.049	1.214	1.372	1.553	1.387	1.010	1.019	0.948	1.098
[2] ACTUAL EXPERIENCE	1.234	1.033	1.047	1.198	1.357	1.425	1.561	1.317	1.201	1.308	1.344	1.193
[3] AMOUNT IN BASE	1.340	1.340	1.340	1.122	1.122	1.122	1.122	1.122	1.122	1.122	1.122	1.122
[4] VARIANCE FROM ACTUAL [1-2]/[2]	2.7%	7.7%	-7.1%	-12.4%	-10.5%	-3.7%	-0.5%	5.3%	-15.9%	-22.1%	-29.5%	-8.0%

DOCKET NO. 98-001-E
UTILITIES DEPARTMENT
EXHIBIT NO. 7



DOCKET NO.1999-001-E
UTILITIES DEPARTMENT
EXHIBIT NO. 6

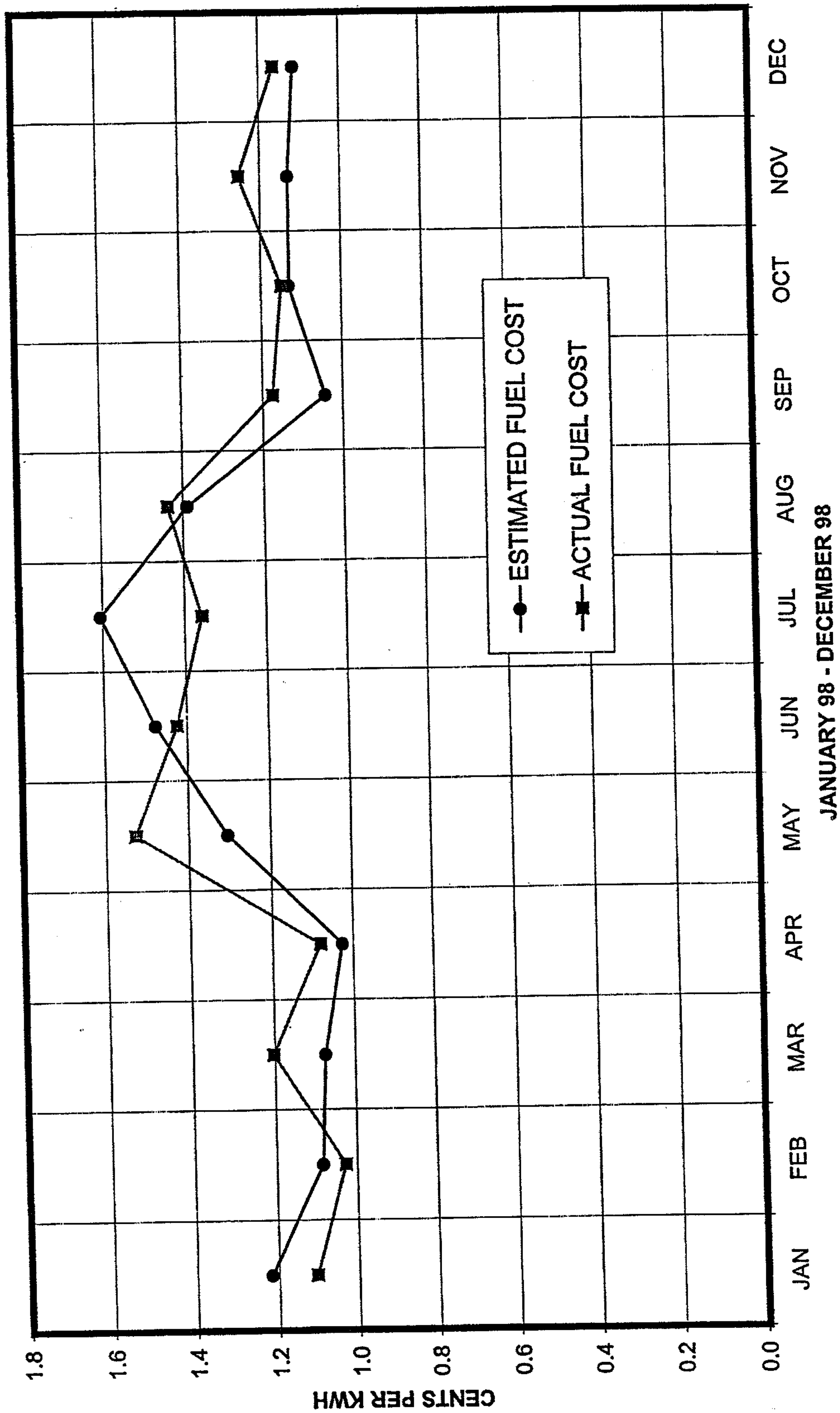
CAROLINA POWER & LIGHT COMPANY

SOUTH CAROLINA RETAIL COMPARISON OF ESTIMATED TO ACTUAL FUEL COST FOR 1998

	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC
[1] ORIGINAL PROJECTION	1.217	1.086	1.075	1.027	1.305	1.478	1.605	1.390	1.045	1.131	1.131	1.115
[2] ACTUAL EXPERIENCE	1.105	1.028	1.203	1.082	1.530	1.425	1.358	1.438	1.176	1.150	1.253	1.165
[3] AMOUNT IN BASE	1.122	1.122	1.122	1.122	1.122	1.122	1.122	1.122	1.122	1.122	1.122	1.122
[4] VARIANCE FROM ACTUAL [1-2]/[2]	10.1%	5.6%	-10.6%	-5.1%	-14.7%	3.7%	18.2%	-3.3%	-11.1%	-1.7%	-9.7%	-4.3%

DOCKET NO.1999-001-E
UTILITIES DEPARTMENT
EXHIBIT NO. 7

CAROLINA POWER & LIGHT COMPANY
ESTIMATED TO ACTUAL FUEL COST



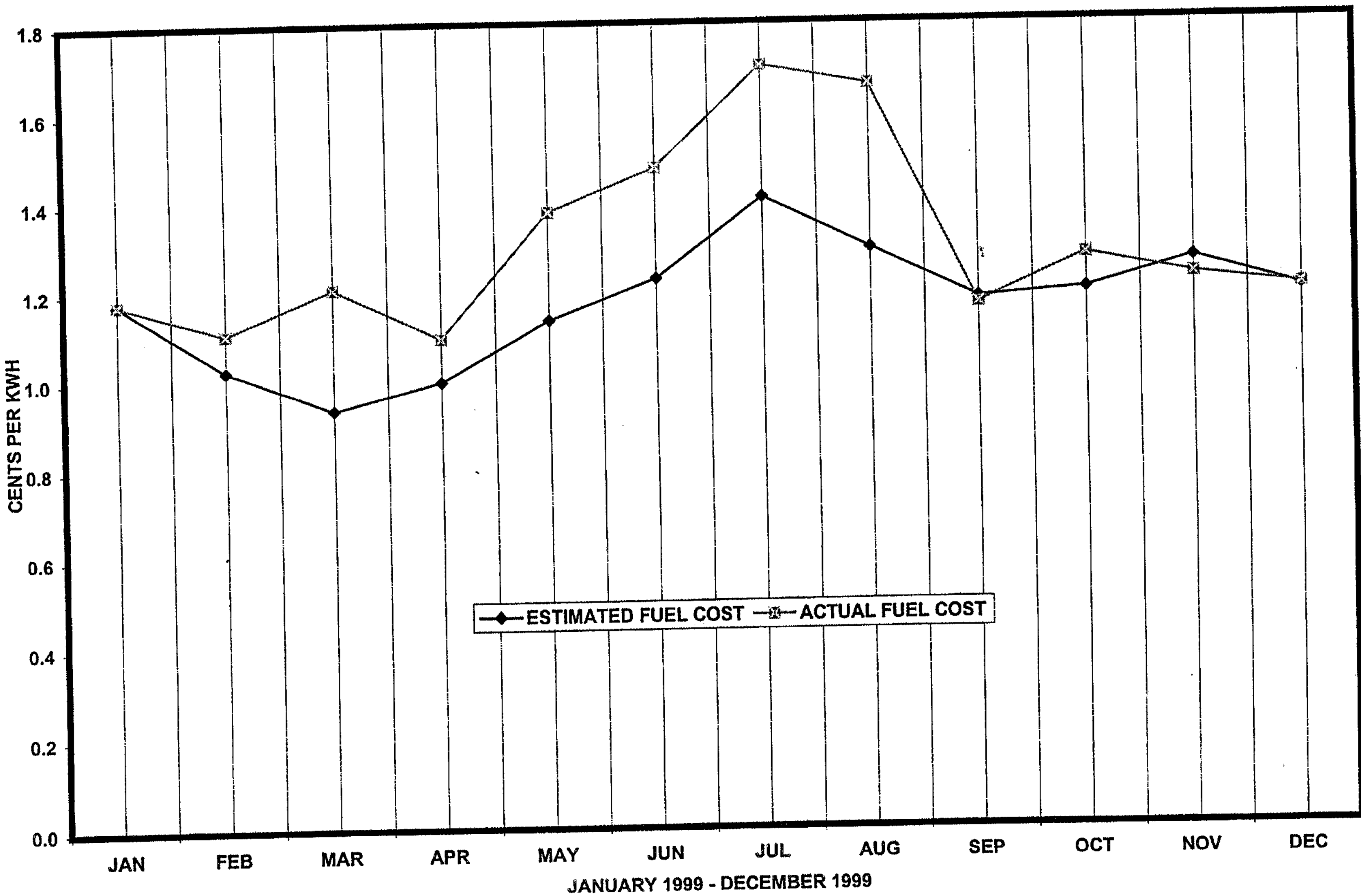
CAROLINA POWER & LIGHT COMPANY
SOUTH CAROLINA RETAIL COMPARISON OF ESTIMATED TO ACTUAL FUEL COST FOR 1999

	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC
[1] ESTIMATED FUEL COST PROJECTION	0.01177	0.01024	0.00934	0.00995	0.01132	0.01224	0.01406	0.01289	0.01175	0.01193	0.01261	0.01193
[2] ACTUAL FUEL COST EXPERIENCE	0.01177	0.01106	0.01207	0.01093	0.01377	0.01474	0.01702	0.01659	0.01163	0.01271	0.01224	0.01197
[3] AMOUNT IN BASE	0.01122	0.01122	0.01122	0.01122	0.01122	0.01122	0.01122	0.01122	0.01122	0.01122	0.01122	0.01122
[4] VARIANCE FROM ACTUAL [1-2]/[2]	0.00%	-7.41%	-22.62%	-8.97%	-17.79%	-16.96%	-17.39%	-22.30%	1.03%	-6.14%	3.02%	-0.33%

DOCKET NO. 2000-001-E
UTILITIES DEPARTMENT
EXHIBIT NO. 6

DOCKET NO. 2000-001-E
UTILITIES DEPARTMENT
EXHIBIT NO. 7

CAROLINA POWER & LIGHT COMPANY
ESTIMATED TO ACTUAL FUEL COST



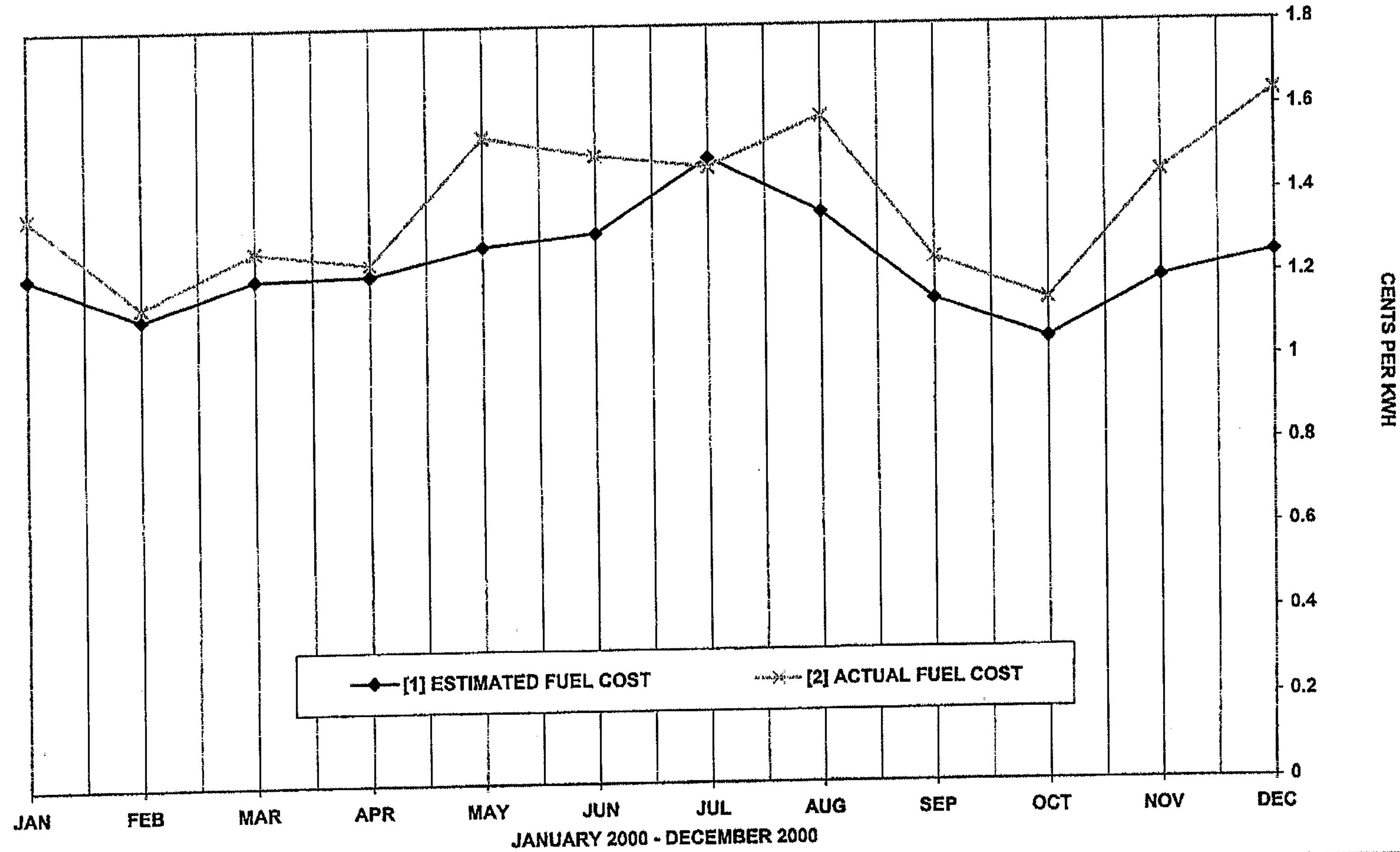
DOCKET NO. 2001-1-E
UTILITIES DEPARTMENT
EXHIBIT NO. 6

CAROLINA POWER & LIGHT COMPANY
SOUTH CAROLINA RETAIL COMPARISON OF ESTIMATED TO ACTUAL FUEL COST FOR 2000

	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC
[1] ESTIMATED FUEL COST PROJECTION	0.01212	0.01108	0.01201	0.01208	0.01277	0.01307	0.01485	0.01354	0.01142	0.01046	0.01191	0.01250
[2] ACTUAL FUEL COST EXPERIENCE	0.01357	0.01138	0.01269	0.01236	0.01539	0.01492	0.01464	0.01583	0.01242	0.01141	0.01445	0.01634
[3] AMOUNT IN BASE	0.01122	0.01122	0.01122	0.01122	0.01265	0.01265	0.01265	0.01265	0.01265	0.01265	0.01265	0.01265
[4] VARIANCE FROM ACTUAL [1-2]/[2]	-10.69%	-2.64%	-5.36%	-2.27%	-17.02%	-12.40%	1.43%	-14.47%	-8.05%	-8.33%	-17.58%	-23.50%

DOCKET NO. 2001-1-E
UTILITIES DEPARTMENT
EXHIBIT NO. 7

CAROLINA POWER & LIGHT COMPANY
ESTIMATED TO ACTUAL FUEL COST



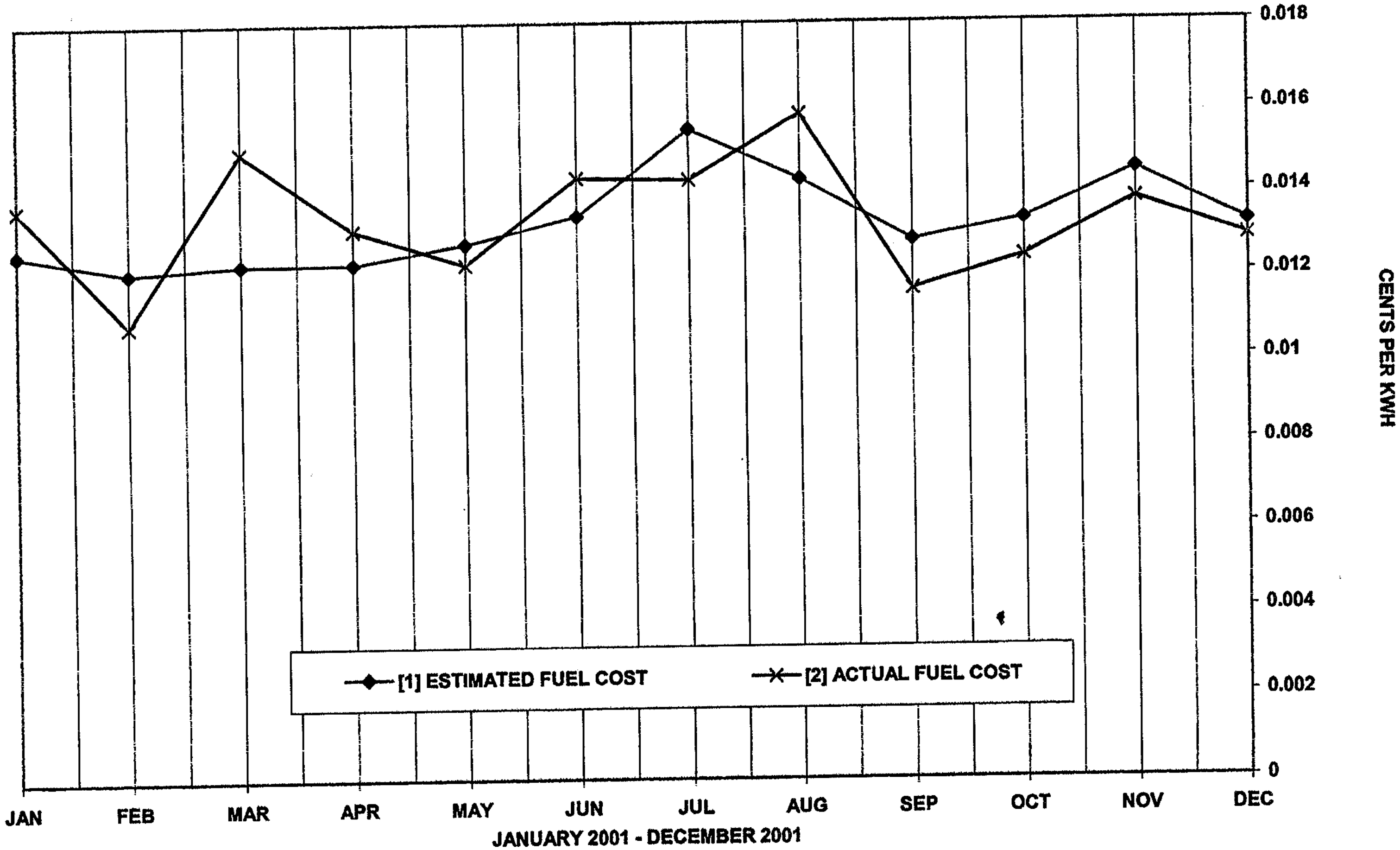
CAROLINA POWER & LIGHT COMPANY
SOUTH CAROLINA RETAIL COMPARISON OF ESTIMATED TO ACTUAL FUEL COST FOR 2001

	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC
[1] ESTIMATED FUEL COST PROJECTION	0.01254	0.01207	0.01225	0.01226	0.01272	0.01338	0.01546	0.01426	0.01278	0.01328	0.01447	0.01319
[2] ACTUAL FUEL COST EXPERIENCE	0.01362	0.01081	0.01495	0.01307	0.01223	0.01430	0.01425	0.01582	0.01160	0.01239	0.01376	0.01284
[3] AMOUNT IN BASE	0.01265	0.01265	0.01265	0.01265	0.01517	0.01517	0.01517	0.01517	0.01517	0.01517	0.01517	0.01517
[4] VARIANCE FROM ACTUAL [1-2]/[2]	-7.93%	11.66%	-18.06%	-6.20%	4.01%	-6.43%	8.49%	-9.86%	10.17%	7.18%	5.16%	2.73%

DOCKET NO. 2002-1-E
UTILITIES DEPARTMENT
EXHIBIT NO. 6

DOCKET NO. 2002-1-E
UTILITIES DEPARTMENT
EXHIBIT NO. 7

CAROLINA POWER & LIGHT COMPANY
ESTIMATED TO ACTUAL FUEL COST



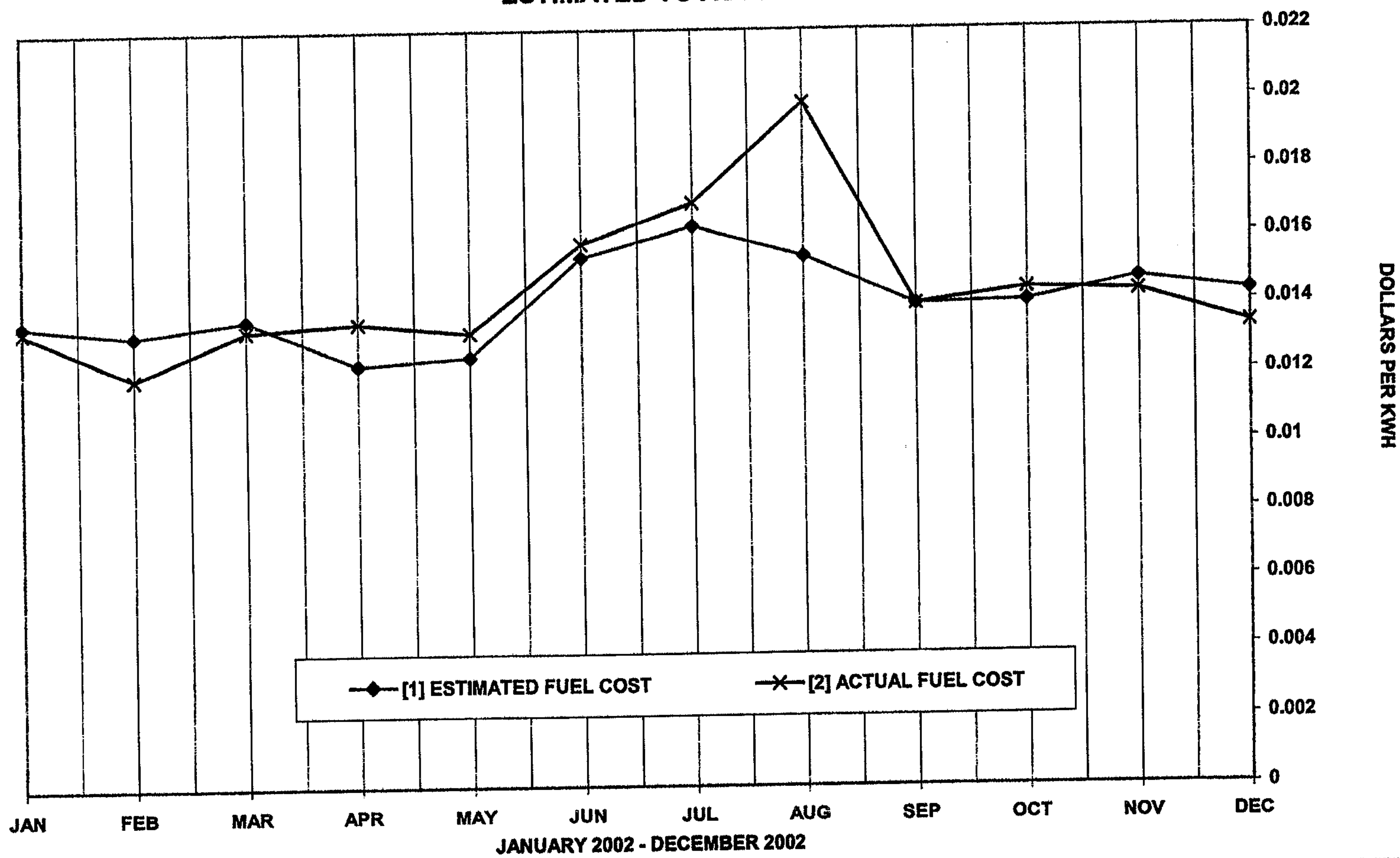
CAROLINA POWER & LIGHT COMPANY
SOUTH CAROLINA RETAIL COMPARISON OF ESTIMATED TO ACTUAL FUEL COST FOR 2002

	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC
[1] ESTIMATED FUEL COST PROJECTION	0.01347	0.01314	0.01357	0.01225	0.01247	0.01534	0.01624	0.01535	0.01394	0.01401	0.01467	0.01428
[2] ACTUAL FUEL COST EXPERIENCE	0.01329	0.01190	0.01325	0.01348	0.01317	0.01574	0.01691	0.01984	0.01394	0.01438	0.01429	0.01333
[3] AMOUNT IN BASE	0.01517	0.01517	0.01517	0.01471	0.01471	0.01471	0.01471	0.01471	0.01471	0.01471	0.01471	0.01471
[4] VARIANCE FROM ACTUAL [1-2]/[2]	1.35%	10.42%	2.42%	-9.12%	-5.32%	-2.54%	-3.96%	-22.63%	0.00%	-2.57%	2.66%	7.13%

DOCKET NO. 2003-1-E
UTILITIES DEPARTMENT
EXHIBIT NO. 6

DOCKET NO. 2003-1-E
UTILITIES DEPARTMENT
EXHIBIT NO. 7

CAROLINA POWER & LIGHT COMPANY
ESTIMATED TO ACTUAL FUEL COST



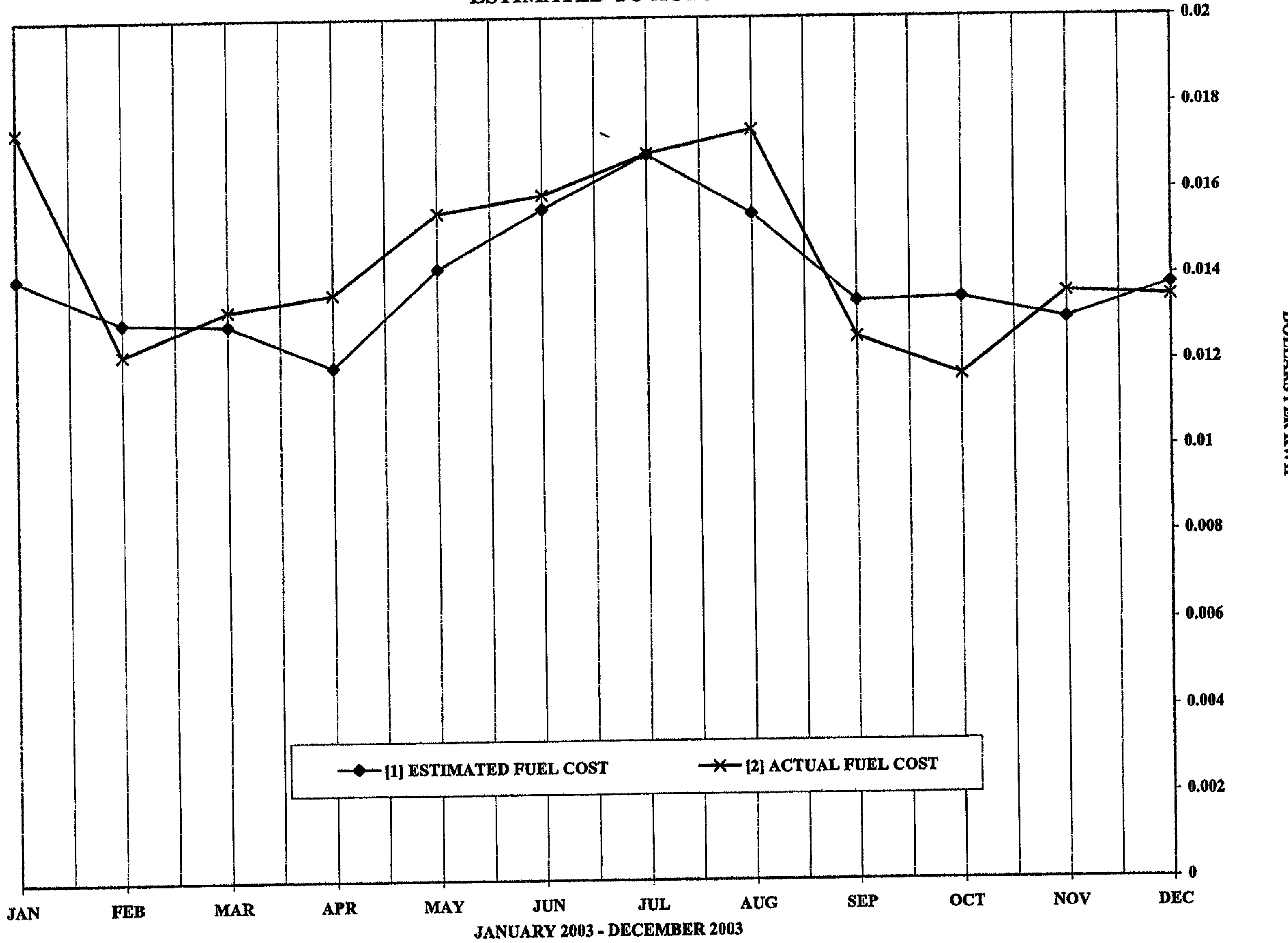
CAROLINA POWER & LIGHT COMPANY
d/b/a PROGRESS ENERGY CAROLINAS, INC.
SOUTH CAROLINA RETAIL COMPARISON OF ESTIMATED TO ACTUAL FUEL COST FOR 2003

	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC
[1] ESTIMATED FUEL COST PROJECTION	0.01401	0.01297	0.01290	0.01191	0.01419	0.01556	0.01682	0.01544	0.01340	0.01347	0.01297	0.01377
[2] ACTUAL FUEL COST EXPERIENCE	0.01743	0.01223	0.01323	0.01361	0.01548	0.01588	0.01684	0.01739	0.01256	0.01167	0.01359	0.01348
[3] AMOUNT IN BASE	0.01471	0.01471	0.01471	0.01471	0.01471	0.01471	0.01471	0.01471	0.01471	0.01471	0.01471	0.01471
[4] VARIANCE FROM ACTUAL [1-2]/[2]	-19.62%	6.05%	-2.49%	-12.49%	-8.33%	-2.02%	-0.12%	-11.21%	6.69%	15.42%	-4.56%	2.15%

DOCKET NO. 2004-1-E
UTILITIES DEPARTMENT
EXHIBIT NO. 6

DOCKET NO. 2004-1-E
UTILITIES DEPARTMENT
EXHIBIT NO. 7

CAROLINA POWER & LIGHT COMPANY
d/b/a PROGRESS ENERGY CAROLINAS, INC.
ESTIMATED TO ACTUAL FUEL COST

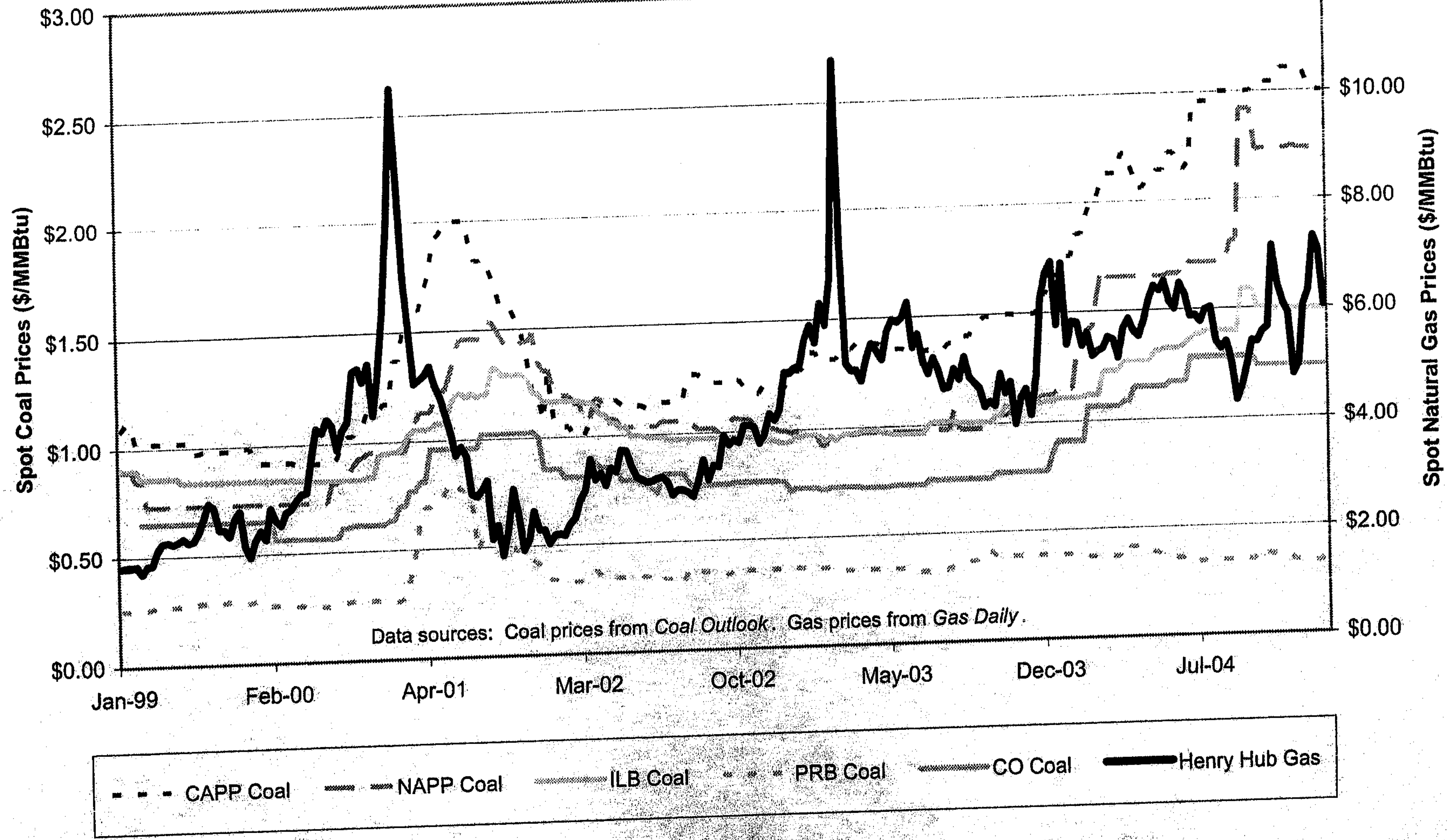


ZARNIKAU

EXHIBIT NO. 9

Introduction

Lots of volatility over the past five years:



PACE | Global Energy Services

ZARNIKAU

EXHIBIT NO. 10

PROGRESS ENERGY CAROLINAS, INC.

Request:

For each coal price forecast prepared by the utility over the past 5 years, please provide:

(a) The forecasted average coal price;
(b) The price actually paid for coal during the historical month; and
(c) A calculation of the forecasting error.

Response:

The forecasted average coal prices for a number of coal qualities, sourced from a variety of regions, for the historical and projected periods, as well as the actual prices for the historical period are attached.

A calculation of the forecasting error could be completed based on any of the forecasted coal qualities

NUC 1-8 CIII
NOVEMBER 2003
GFF

(Enter values for the Blue cells)

JD Energy, Inc.

Sep-03

QUARTERLY COAL FORECAST - Base Case

Base Case

ANNUAL AVERAGE SPOT PRICES - NOMINAL DOLLARS PER TON

	Year	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013
	Northern Appalachia											
2.44	-1.6% 13115 BTU	$30.94	$31.48	$30.13	$29.95	$30.27	$30.92	$32.10	$33.12	$33.45	$33.54	$33.70
2.74	-1.8% 13115 BTU	$29.98	$30.55	$29.19	$29.07	$29.41	$30.09	$31.29	$32.35	$32.78	$32.96	$33.18
3.35	-2.2% 13115 BTU	$28.55	$29.15	$27.79	$27.74	$28.11	$28.84	$30.06	$31.19	$31.77	$32.10	$32.41
4.57	-3% 13115 BTU	$24.53	$24.09	$22.17	$22.58	$23.24	$23.72	$24.73	$25.66	$26.18	$28.47	$26.74
	Central Appalachia											
1.13	-.7% 12400 BTU	$33.79	$35.39	$35.50	$35.71	$36.00	$36.13	$36.41	$36.76	$37.60	$38.67	$39.72
1.08	-.7% 13000 BTU	$36.25	$37.99	$38.12	$38.35	$38.68	$38.82	$39.10	$39.39	$40.19	$41.30	$42.42
1.67	-1.0% 12000 BTU	$30.54	$32.53	$32.55	$32.49	$32.47	$32.48	$33.53	$34.81	$35.57	$36.31	$37.10
2.50	-1.5% 12000 BTU	$28.04	$29.99	$29.94	$29.60	$29.34	$29.23	$30.15	$31.38	$32.90	$33.97	$35.40

	Year	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
	Northern Appalachia											
2.44	-1.6% 13115 BTU	$33.92	$34.19	$34.43	$34.76	$35.10	$35.48	$35.88	$36.37	$36.89	$37.41	$37.93
2.74	-1.8% 13115 BTU	$33.44	$33.72	$33.98	$34.31	$34.67	$35.07	$35.49	$35.96	$36.46	$36.96	$37.46
3.35	-2.2% 13115 BTU	$32.72	$33.02	$33.30	$33.62	$34.01	$34.44	$34.91	$35.36	$35.80	$36.28	$36.75
4.57	-3% 13115 BTU	$27.00	$27.26	$27.51	$27.80	$28.14	$28.53	$28.91	$29.31	$29.74	$30.16	$30.58
	Central Appalachia											
1.13	-.7% 12400 BTU	$40.63	$41.31	$42.28	$43.51	$44.84	$46.24	$47.71	$49.24	$50.83	$52.46	$54.14
1.08	-.7% 13000 BTU	$43.39	$44.11	$45.16	$46.47	$47.89	$49.39	$50.96	$52.60	$54.29	$56.05	$57.85
1.67	-1.0% 12000 BTU	$38.33	$39.49	$40.59	$41.60	$42.68	$43.84	$45.04	$46.29	$47.57	$49.05	$50.57
2.50	-1.5% 12000 BTU	$37.04	$38.59	$39.88	$40.89	$41.98	$43.18	$44.39	$45.64	$46.92	$48.40	$49.91

Coal prices developed using JD Energy Quarterly Coal Forecast September 2003

#SO2/mmBtu	Northern Appalachia BTU	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013
2.44	13115	$30.94	$31.48	$30.13	$29.95	$30.27	$30.92	$32.10	$33.12	$33.45	$33.54	$33.70
2.74	13115	$29.98	$30.55	$29.19	$29.07	$29.41	$30.09	$31.28	$32.35	$32.78	$32.96	$33.18
3.35	13115	$28.55	$29.15	$27.79	$27.74	$28.11	$28.84	$30.06	$31.19	$31.77	$32.10	$32.41
4.57	13115	$24.53	$24.09	$22.17	$22.58	$23.24	$23.72	$24.73	$25.66	$26.18	$26.47	$26.74

#SO2/mmBtu	Northern Appalachia BTU	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
2.44	13115	$33.92	$34.19	$34.43	$34.76	$35.10	$35.48	$35.88	$36.37	$36.89	$37.41	$37.93
2.74	13115	$33.44	$33.72	$33.98	$34.31	$34.67	$35.07	$35.49	$35.96	$36.46	$36.96	$37.46
3.35	13115	$32.72	$33.02	$33.30	$33.62	$34.01	$34.44	$34.91	$35.36	$35.80	$36.28	$36.75
4.57	13115	$27.00	$27.26	$27.51	$27.80	$28.14	$28.53	$28.91	$29.31	$29.74	$30.16	$30.58

#SO2/mmBtu	Central Appalachia BTU	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013
1.13	12400	$33.79	$35.39	$35.50	$35.71	$36.00	$36.13	$36.41	$36.76	$37.60	$38.67	$39.72
1.20	12,500	$34.05	$35.67	$35.79	$35.99	$36.29	$36.42	$36.70	$37.06	$37.90	$38.98	$40.04
1.67	12,000	$30.54	$32.53	$32.55	$32.49	$32.47	$32.48	$33.53	$34.81	$35.57	$36.31	$37.10
1.67	12,500	$31.81	$33.88	$33.91	$33.85	$33.82	$33.84	$34.93	$36.26	$37.05	$37.82	$38.64
2.50	12,000	$28.04	$29.99	$29.94	$29.60	$29.34	$29.23	$30.15	$31.38	$32.90	$33.97	$35.40

#SO2/mmBtu	Central Appalachia BTU	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
1.13	12400	$40.63	$41.31	$42.28	$43.51	$44.84	$46.24	$47.71	$49.24	$50.83	$52.46	$54.14
1.20	12,500	$40.96	$41.64	$42.63	$43.86	$45.20	$46.61	$48.10	$49.64	$51.24	$52.89	$54.59
1.67	12,000	$38.33	$39.49	$40.59	$41.60	$42.68	$43.84	$45.04	$46.29	$47.57	$49.05	$50.57
1.67	12,500	$39.93	$41.13	$42.28	$43.33	$44.46	$45.66	$46.92	$48.22	$49.56	$51.10	$52.68
2.50	12,000	$37.04	$38.59	$39.88	$40.89	$41.98	$43.18	$44.39	$45.64	$46.92	$48.40	$49.91

NAPP Coal ($/ton) Price Table

Year	1	2	3	4
Coal Number for Scrubber Curves	1	2	3	4
Average BTU/lb. coal	13,115	13,115	13,115	13,115
Average lbs. SO2/mmBTU	2.44	2.74	3.35	4.57
2004	$31.48	$30.55	$29.15	$24.09
2005	$30.13	$29.19	$27.79	$22.17
2006	$29.95	$29.07	$27.74	$22.58
2007	$30.27	$29.41	$28.11	$23.24
2008	$30.92	$30.09	$28.84	$23.72
2009	$32.10	$31.28	$30.06	$24.73
2010	$33.12	$32.35	$31.19	$25.66
2011	$33.45	$32.78	$31.77	$26.18
2012	$33.54	$32.96	$32.10	$26.47
2013	$33.70	$33.18	$32.41	$26.74
2014	$33.92	$33.44	$32.72	$27.00
2015	$34.19	$33.72	$33.02	$27.26
2016	$34.43	$33.98	$33.30	$27.51
2017	$34.76	$34.31	$33.62	$27.80
2018	$35.10	$34.67	$34.01	$28.14
2019	$35.48	$35.07	$34.44	$28.53
2020	$35.88	$35.49	$34.91	$28.91
2021	$36.37	$35.96	$35.36	$29.31
2022	$36.89	$36.46	$35.80	$29.74
2023	$37.41	$36.96	$36.28	$30.16
2024	$37.93	$37.46	$36.75	$30.58

CAPP Coal ($/ton) Price Table

Year	5	6	7	8	9
Average BTU/lb. coal	12,400	12,500	12,000	12,500	12,000
Average lbs. SO2/mmBTU	1.13	1.20	1.67	1.67	2.50
2004	$35.39	$35.67	$32.53	$33.88	$29.99
2005	$35.50	$35.79	$32.55	$33.91	$29.94
2006	$35.71	$35.99	$32.49	$33.85	$29.60
2007	$36.00	$36.29	$32.47	$33.82	$29.34
2008	$36.13	$36.42	$32.48	$33.84	$29.23
2009	$36.41	$36.70	$33.53	$34.93	$30.15
2010	$36.76	$37.06	$34.81	$36.26	$31.38
2011	$37.60	$37.90	$35.57	$37.05	$32.90
2012	$38.67	$38.98	$36.31	$37.82	$33.97
2013	$39.72	$40.04	$37.10	$38.64	$35.40
2014	$40.63	$40.96	$38.33	$39.93	$37.04
2015	$41.31	$41.64	$39.49	$41.13	$38.59
2016	$42.28	$42.63	$40.59	$42.28	$39.88
2017	$43.51	$43.86	$41.60	$43.33	$40.89
2018	$44.84	$45.20	$42.68	$44.46	$41.98
2019	$46.24	$46.61	$43.84	$45.66	$43.18
2020	$47.71	$48.10	$45.04	$46.92	$44.39
2021	$49.24	$49.64	$46.29	$48.22	$45.64
2022	$50.83	$51.24	$47.57	$49.56	$46.92
2023	$52.46	$52.89	$49.05	$51.10	$48.40
2024	$54.14	$54.59	$50.57	$52.68	$49.91

NAPP Coal ($/mmBtu) Price Table

Year				
Average BTU/lb. coal	13,115	13,115	13,115	13,115
Average lbs. SO2/mmBTU	2.44	2.74	3.35	4.57
2004	$1.20	$1.16	$1.11	$0.92
2005	$1.15	$1.11	$1.06	$0.85
2006	$1.14	$1.11	$1.06	$0.86
2007	$1.15	$1.12	$1.07	$0.89
2008	$1.18	$1.15	$1.10	$0.90
2009	$1.22	$1.19	$1.16	$0.94
2010	$1.26	$1.23	$1.19	$0.98
2011	$1.28	$1.25	$1.21	$1.00
2012	$1.28	$1.26	$1.22	$1.01
2013	$1.28	$1.26	$1.24	$1.02
2014	$1.29	$1.27	$1.25	$1.03
2015	$1.30	$1.29	$1.26	$1.04
2016	$1.31	$1.30	$1.27	$1.05
2017	$1.33	$1.31	$1.28	$1.06
2018	$1.34	$1.32	$1.30	$1.07
2019	$1.35	$1.34	$1.31	$1.09
2020	$1.37	$1.35	$1.33	$1.10
2021	$1.39	$1.37	$1.35	$1.12
2022	$1.41	$1.39	$1.36	$1.13
2023	$1.43	$1.41	$1.38	$1.15
2024	$1.45	$1.43	$1.40	$1.17

CAPP Coal ($/mmBtu) Price Table

Year					
Average BTU/lb. coal	12,400	12,500	12,000	12,500	12,000
Average lbs. SO2/mmBTU	1.13	1.20	1.67	1.67	2.50
2004	$1.43	$1.43	$1.36	$1.36	$1.25
2005	$1.43	$1.43	$1.36	$1.36	$1.25
2006	$1.44	$1.44	$1.35	$1.35	$1.23
2007	$1.45	$1.45	$1.35	$1.35	$1.22
2008	$1.46	$1.46	$1.35	$1.35	$1.22
2009	$1.47	$1.47	$1.40	$1.40	$1.26
2010	$1.48	$1.48	$1.45	$1.45	$1.31
2011	$1.52	$1.52	$1.48	$1.48	$1.37
2012	$1.56	$1.56	$1.51	$1.51	$1.42
2013	$1.60	$1.60	$1.55	$1.55	$1.48
2014	$1.64	$1.64	$1.60	$1.60	$1.54
2015	$1.67	$1.67	$1.65	$1.65	$1.61
2016	$1.71	$1.71	$1.69	$1.69	$1.66
2017	$1.75	$1.75	$1.73	$1.73	$1.70
2018	$1.81	$1.81	$1.78	$1.78	$1.75
2019	$1.86	$1.86	$1.83	$1.83	$1.80
2020	$1.92	$1.92	$1.88	$1.88	$1.85
2021	$1.99	$1.99	$1.93	$1.93	$1.90
2022	$2.05	$2.05	$1.98	$1.98	$1.95
2023	$2.12	$2.12	$2.04	$2.04	$2.02
2024	$2.18	$2.18	$2.11	$2.11	$2.08

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Sutton Incremental Barge Forecast (10)

Foreign coal incrementals per recent market assessments. When escalation rate in effect it is 2%.

Year	Incremental $/mt	$/ton	% increase
	12800	12800	
	1.5	1.5	
2003	$36.53	$33 14	
2004	$37.26	$33.80	2%
2005	$38.01	$34 48	2%
2006	$38.77	$35.17	2%
2007	$39.54	$35.87	2%
2008	$40.33	$36.59	2%
2009	$41.14	$37.32	2%
2010	$41.96	$38.07	2%
2011	$42.80	$38.83	2%
2012	$43.66	$39.60	2%
2013	$44.53	$40.40	2%
2014	$45.42	$41.20	2%
2015	$46.33	$42.03	2%
2016	$47.26	$42.87	2%
2017	$48.20	$43.73	2%
2018	$49.16	$44.60	2%
2019	$50.15	$45.49	2%
2020	$51.15	$46.40	2%
2021	$52.17	$47.33	2%
2022	$53.22	$48.28	2%
2023	$54 28	$49.24	2%
2024	$55 37	$50.23	2%

Sutton Incremental Transportation Rates - Barge and Ocean Vessel Rates per Jerry Boyd

Barge Transportation

Year	$/ton	% increase
2003	$8.34	
2004	$8.34	2%
2005	$8.34	2%
2006	$8.51	2%
2007	$8.68	2%
2008	$8.85	2%
2009	$9.03	2%
2010	$9.21	2%
2011	$9.39	2%
2012	$9.58	2%
2013	$9.77	2%
2014	$9.97	2%
2015	$10.17	2%
2016	$10.37	2%
2017	$10.58	2%
2018	$10.79	2%
2019	$11.00	2%
2020	$11.22	2%
2021	$11.45	2%
2022	$11.68	2%
2023	$11.91	2%
2024	$12.15	2%

Ocean Vessel Transportation

Year	$/Metric Ton		$/ton
2003	$13.00		$11 79
2004	$13.00	2%	$11.79
2005	$10.00	2%	$9 07
2006	$8.00	2%	$7 26
2007	$8.16	2%	$7 40
2008	$8.32	2%	$7 55
2009	$8.49	2%	$7 70
2010	$8.66	2%	$7 86
2011	$8.83	2%	$8 01
2012	$9.01	2%	$8 17
2013	$9.19	2%	$8 34
2014	$9.37	2%	$8 50
2015	$9.56	2%	$8 67
2016	$9.75	2%	$8 85
2017	$9.95	2%	$9 02
2018	$10.15	2%	$9 20
2019	$10.35	2%	$9 39
2020	$10.56	2%	$9 58
2021	$10.77	2%	$9 77
2022	$10.98	2%	$9.96
2023	$11.20	2%	$10 16
2024	$11.43	2%	$10 37

Total Delivered Barge Incrementals

Total Incremental Price Delivered

BTU	12800	
SO2/mmBtu	1.50	
Year	$/ton	$/mmBtu
2004	$53.94	$2.1069
2005	$51.89	$2 0270
2006	$50.93	$1.9895
2007	$51.95	$2.0293
2008	$52.99	$2 0699
2009	$54.05	$2 1113
2010	$55.13	$2.1535
2011	$56.23	$2.1966
2012	$57.36	$2 2405
2013	$58.51	$2.2854
2014	$59.68	$2 3311
2015	$60.87	$2.3777
2016	$62.09	$2 4252
2017	$63.33	$2.4737
2018	$64.59	$2.5232
2019	$65.89	$2 5737
2020	$67.20	$2.6252
2021	$68.55	$2 6777
2022	$69.92	$2 7312
2023	$71.32	$2.7858
2024	$72.74	$2.8416

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(Enter values for the Blue cells)

JD Energy, Inc.

Feb-04

QUARTERLY COAL FORECAST - Base Case

Base Case

ANNUAL AVERAGE SPOT PRICES - NOMINAL DOLLARS PER TON

	Year:	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
	Northern Appalachia												
2.44	-1.6%, 13115 BTU	$35.83	$30.13	$30.13	$30.17	$30.69	$31.72	$32.66	$33.00	$33.10	$33.24	$33.47	$33.80
2.74	-1.8%, 13115 BTU	$34.93	$29.19	$29.19	$29.33	$29.88	$30.93	$31.91	$32.35	$32.54	$32.74	$33.01	$33.35
3.35	-2.5%, 13115 BTU	$33.59	$27.79	$27.79	$28.07	$28.67	$29.74	$30.79	$31.38	$31.71	$31.99	$32.31	$32.67
4.57	-3%, 13115 BTU	$27.75	$22.17	$22.62	$23.20	$23.58	$24.47	$25.33	$25.86	$26.15	$26.40	$26.67	$26.98
	Central Appalachia												
1.13	-.7%, 12400 BTU	$41.09	$35.59	$34.98	$35.13	$35.12	$35.21	$35.47	$36.30	$37.33	$38.32	$39.21	$39.94
1.08	-.7%, 13000 BTU	$44.11	$38.21	$37.58	$37.75	$37.73	$37.82	$38.01	$38.79	$39.88	$40.93	$41.88	$42.66
1.67	-1.0%, 12000 BTU	$38.25	$32.63	$31.84	$31.68	$31.57	$32.43	$33.59	$34.34	$35.05	$35.79	$36.99	$38.19
2.50	-1.5%, 12000 BTU	$35.71	$30.02	$29.00	$28.64	$28.42	$29.16	$30.28	$31.76	$32.80	$34.16	$35.75	$37.32
	Illinois Basin												
3.5	-3%, 11000 BTU (IL	$20.74	$20.14	$20.13	$20.63	$21.45	$22.41	$23.54	$24.55	$25.10	$25.58	$26.08	$26.63
3.5	-3%, 11000 BTU (K	$23.05	$22.19	$22.17	$22.62	$23.41	$24.30	$25.47	$26.53	$27.11	$27.66	$28.23	$28.86

	Year:	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
	Northern Appalachia										
2.44	-1.6%, 13115 BTU	$34.12	$34.51	$34.88	$35.27	$35.67	$36.16	$36.69	$37.20	$37.72	$38.27
2.74	-1.8%, 13115 BTU	$33.68	$34.07	$34.45	$34.87	$35.29	$35.77	$36.26	$36.75	$37.26	$37.78
3.35	-2.5%, 13115 BTU	$33.02	$33.40	$33.81	$34.26	$34.73	$35.18	$35.62	$36.09	$36.57	$37.06
4.57	-3%, 13115 BTU	$27.29	$27.62	$27.98	$28.39	$28.76	$29.16	$29.59	$30.00	$30.43	$30.88
	Central Appalachia										
1.13	-.7%, 12400 BTU	$40.98	$42.24	$43.57	$44.96	$46.39	$47.88	$49.43	$51.01	$52.65	$54.35
1.08	-.7%, 13000 BTU	$43.77	$45.11	$46.53	$48.01	$49.54	$51.14	$52.80	$54.49	$56.25	$58.07
1.67	-1.0%, 12000 BTU	$39.34	$40.38	$41.47	$42.62	$43.79	$45.01	$46.26	$47.69	$49.18	$50.71
2.50	-1.5%, 12000 BTU	$38.66	$39.70	$40.79	$41.98	$43.16	$44.38	$45.63	$47.05	$48.53	$50.06
	Illinois Basin										
3.5	-3%, 11000 BTU (IL	$27.18	$27.77	$28.40	$29.07	$29.77	$30.48	$31.22	$31.97	$32.74	$33.53
3.5	-3%, 11000 BTU (K	$29.49	$30.17	$30.89	$31.66	$32.45	$33.27	$34.11	$34.97	$35.85	$36.76

Coal prices developed using JD Energy Quarterly Coal Forecast February 20, 2004

Northern Appalachia

#SO2/mmBtu	BTU	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
2.44	13115	$35.83	$30.13	$30.13	$30.17	$30.69	$31.72	$32.66	$33.00	$33.10	$33.24	$33.47	$33.80
2.74	13115	$34.93	$29.19	$29.19	$29.33	$29.88	$30.93	$31.91	$32.35	$32.54	$32.74	$33.01	$33.35
3.35	13115	$33.59	$27.79	$27.79	$28.07	$28.67	$29.74	$30.79	$31.38	$31.71	$31.99	$32.31	$32.67
4.57	13115	$27.75	$22.17	$22.62	$23.20	$23.58	$24.47	$25.33	$25.86	$26.15	$26.40	$26.67	$26.98

#SO2/mmBtu	BTU	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
2.44	13115	$34.12	$34.51	$34.88	$35.27	$35.67	$36.16	$36.69	$37.20	$37.72	$38.27
2.74	13115	$33.68	$34.07	$34.45	$34.87	$35.29	$35.77	$36.26	$36.75	$37.26	$37.78
3.35	13115	$33.02	$33.40	$33.81	$34.26	$34.73	$35.18	$35.62	$36.09	$36.57	$37.06
4.57	13115	$27.29	$27.62	$27.98	$28.39	$28.76	$29.16	$29.59	$30.00	$30.43	$30.88

Central Appalachia

#SO2/mmBtu	BTU	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
1.13	12400	$41.09	$35.59	$34.98	$35.13	$35.12	$35.21	$35.47	$36.30	$37.33	$38.32	$39.21	$39.94
1.20	12,500	$41.42	$35.87	$35.27	$35.41	$35.40	$35.49	$35.76	$36.59	$37.63	$38.63	$39.53	$40.27
1.67	12,000	$38.25	$32.63	$31.84	$31.68	$31.57	$32.43	$33.59	$34.34	$35.05	$35.79	$36.99	$38.19
1.67	12,500	$39.84	$33.98	$33.16	$33.00	$32.89	$33.78	$34.99	$35.77	$36.51	$37.29	$38.53	$39.78
2.50	12,000	$35.71	$30.02	$29.00	$28.64	$28.42	$29.16	$30.28	$31.76	$32.80	$34.16	$35.75	$37.32

#SO2/mmBtu	BTU	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
1.13	12400	$40.98	$42.24	$43.57	$44.96	$46.39	$47.88	$49.43	$51.01	$52.65	$54.35
1.20	12,500	$41.31	$42.58	$43.92	$45.32	$46.76	$48.27	$49.82	$51.42	$53.08	$54.79
1.67	12,000	$39.34	$40.38	$41.47	$42.62	$43.79	$45.01	$46.26	$47.69	$49.18	$50.71
1.67	12,500	$40.98	$42.07	$43.20	$44.39	$45.61	$46.88	$48.19	$49.68	$51.23	$52.82
2.50	12,000	$38.66	$39.70	$40.79	$41.98	$43.16	$44.38	$45.63	$47.05	$48.53	$50.06

Illinois Basin

#SO2/mmBtu	BTU	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
3.50	11000	$20.74	$20.14	$20.13	$20.63	$21.45	$22.41	$23.54	$24.55	$25.10	$25.58	$26.08	$26.63
3.50	11000	$23.05	$22.19	$22.17	$22.62	$23.41	$24.30	$25.47	$26.53	$27.11	$27.66	$28.23	$28.86

#SO2/mmBtu	BTU	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
3.50	11000	$27.18	$27.77	$28.40	$29.07	$29.77	$30.48	$31.22	$31.97	$32.74	$33.53
3.50	11000	$29.49	$30.17	$30.89	$31.66	$32.45	$33.27	$34.11	$34.97	$35.85	$36.76

NAPP Coal ($/ton) Price Table

Year	1	2	3	4
Coal Number for Scrubber Curves	1	2	3	4
Average BTU/lb. coal	13,115	13,115	13,115	13,115
Average lbs. SO2/mmBTU	2.44	2.74	3.35	4.57
2004	$35.83	$34.93	$33.59	$27.75
2005	$30.13	$29.19	$27.79	$22.17
2006	$30.13	$29.19	$27.79	$22.62
2007	$30.17	$29.33	$28.07	$23.20
2008	$30.69	$29.88	$28.67	$23.58
2009	$31.72	$30.93	$29.74	$24.47
2010	$32.66	$31.91	$30.79	$25.33
2011	$33.00	$32.35	$31.38	$25.86
2012	$33.10	$32.54	$31.71	$26.15
2013	$33.24	$32.74	$31.99	$26.40
2014	$33.47	$33.01	$32.31	$26.67
2015	$33.80	$33.35	$32.67	$26.98
2016	$34.12	$33.68	$33.02	$27.29
2017	$34.51	$34.07	$33.40	$27.62
2018	$34.88	$34.45	$33.81	$27.98
2019	$35.27	$34.87	$34.26	$28.39
2020	$35.67	$35.29	$34.73	$28.76
2021	$36.16	$35.77	$35.18	$29.16
2022	$36.69	$36.26	$35.62	$29.59
2023	$37.20	$36.75	$36.09	$30.00
2024	$37.72	$37.26	$36.57	$30.43
2025	$38.27	$37.78	$37.06	$30.88

CAPP Coal ($/ton) Price Table

Year	5	6	7	8	9
Average BTU/lb. coal	12,400	12,500	12,000	12,500	12,000
Average lbs. SO2/mmBTU	1.13	1.20	1.67	1.67	2.50
2004	$41.09	$41.42	$38.25	$39.84	$35.71
2005	$35.59	$35.87	$32.63	$33.98	$30.02
2006	$34.98	$35.27	$31.84	$33.16	$29.00
2007	$35.13	$35.41	$31.68	$33.00	$28.64
2008	$35.12	$35.40	$31.57	$32.89	$28.42
2009	$35.21	$35.49	$32.43	$33.78	$29.16
2010	$35.47	$35.76	$33.59	$34.99	$30.28
2011	$36.30	$36.59	$34.34	$35.77	$31.76
2012	$37.33	$37.63	$35.05	$36.51	$32.80
2013	$38.32	$38.63	$35.79	$37.29	$34.16
2014	$39.21	$39.53	$36.99	$38.53	$35.75
2015	$39.94	$40.27	$38.19	$39.78	$37.32
2016	$40.98	$41.31	$39.34	$40.98	$38.66
2017	$42.24	$42.59	$40.38	$42.07	$39.70
2018	$43.57	$43.92	$41.47	$43.20	$40.79
2019	$44.96	$45.32	$42.62	$44.39	$41.98
2020	$46.39	$46.76	$43.79	$45.61	$43.16
2021	$47.88	$48.27	$45.01	$46.88	$44.38
2022	$49.43	$49.82	$46.26	$48.19	$45.63
2023	$51.01	$51.42	$47.69	$49.68	$47.05
2024	$52.65	$53.08	$49.18	$51.23	$48.53
2025	$54.35	$54.79	$50.71	$52.82	$50.06

Illinois Basin Coal ($/ton) Price Table

Year	11
Average BTU/lb. coal	11000
Average lbs. SO2/mmBTU	3.50
2004	$23.05
2005	$22.19
2006	$22.17
2007	$22.62
2008	$23.41
2009	$24.30
2010	$25.47
2011	$26.53
2012	$27.11
2013	$27.66
2014	$28.23
2015	$28.86
2016	$29.49
2017	$30.17
2018	$30.89
2019	$31.66
2020	$32.45
2021	$33.27
2022	$34.11
2023	$34.97
2024	$35.85
2025	$36.76

NAPP Coal ($/mmBtu) Price Table

Year				
Average BTU/lb. coal	13,115	13,115	13,115	13,115
Average lbs. SO2/mmBTU	2.44	2.74	3.35	4.57
2004	$1.37	$1.33	$1.28	$1.06
2005	$1.15	$1.11	$1.06	$0.85
2006	$1.15	$1.11	$1.06	$0.86
2007	$1.15	$1.12	$1.07	$0.88
2008	$1.17	$1.14	$1.09	$0.90
2009	$1.21	$1.18	$1.13	$0.93
2010	$1.25	$1.22	$1.17	$0.97
2011	$1.26	$1.23	$1.20	$0.99
2012	$1.26	$1.24	$1.21	$1.00
2013	$1.27	$1.25	$1.22	$1.01
2014	$1.28	$1.26	$1.23	$1.02
2015	$1.29	$1.27	$1.25	$1.03
2016	$1.30	$1.28	$1.26	$1.04
2017	$1.32	$1.30	$1.27	$1.05
2018	$1.33	$1.31	$1.29	$1.07
2019	$1.34	$1.33	$1.31	$1.08
2020	$1.36	$1.35	$1.32	$1.10
2021	$1.38	$1.36	$1.34	$1.11
2022	$1.40	$1.38	$1.36	$1.13
2023	$1.42	$1.40	$1.38	$1.14
2024	$1.44	$1.42	$1.39	$1.16
[illegible]	$1.46	$1.44	$1.41	$1.18

CAPP Coal ($/mmBtu) Price Table

Year					
Average BTU/lb. coal	12,400	12,500	12,000	12,500	12,000
Average lbs. SO2/mmBTU	1.13	1.20	1.67	1.67	2.50
2004	$1.66	$1.66	$1.59	$1.59	$1.49
2005	$1.43	$1.43	$1.36	$1.36	$1.25
2006	$1.41	$1.41	$1.33	$1.33	$1.21
2007	$1.42	$1.42	$1.32	$1.32	$1.19
2008	$1.42	$1.42	$1.32	$1.32	$1.18
2009	$1.42	$1.42	$1.35	$1.35	$1.21
2010	$1.43	$1.43	$1.40	$1.40	$1.26
2011	$1.46	$1.46	$1.43	$1.43	$1.32
2012	$1.51	$1.51	$1.46	$1.46	$1.37
2013	$1.55	$1.55	$1.49	$1.49	$1.42
2014	$1.58	$1.58	$1.54	$1.54	$1.49
2015	$1.61	$1.61	$1.59	$1.59	$1.56
2016	$1.65	$1.65	$1.64	$1.64	$1.61
2017	$1.70	$1.70	$1.68	$1.68	$1.65
2018	$1.76	$1.76	$1.73	$1.73	$1.70
2019	$1.81	$1.81	$1.78	$1.78	$1.75
2020	$1.87	$1.87	$1.82	$1.82	$1.80
2021	$1.93	$1.93	$1.88	$1.88	$1.85
2022	$1.99	$1.99	$1.93	$1.93	$1.90
2023	$2.06	$2.06	$1.99	$1.99	$1.96
2024	$2.12	$2.12	$2.05	$2.05	$2.02
2025	$2.19	$2.19	$2.11	$2.11	$2.09

Illinois Basin ($/mmBtu) Price Table

Year	
	11,000
	3.50
2004	$1.05
2005	$1.01
2006	$1.01
2007	$1.03
2008	$1.06
2009	$1.10
2010	$1.16
2011	$1.21
2012	$1.23
2013	$1.26
2014	$1.28
2015	$1.31
2016	$1.34
2017	$1.37
2018	$1.40
2019	$1.44
2020	$1.48
2021	$1.51
2022	$1.55
2023	$1.59
2024	$1.63
2025	$1.67

NUC 1-38a
APRIL 2004
GFF

Sutton Incremental Barge Forecast

Foreign coal incrementals per recent market assessments. When escalation rate in effect it is 2%.

Year	Incremental $/mt	$/ton	% increase
	12800	12800	
	1.5	1.5	
2003	$36.53	$33.14	
2004	$37.26	$33.80	2%
2005	$38.01	$34.48	2%
2006	$38.77	$35.17	2%
2007	$39.54	$35.87	2%
2008	$40.33	$36.59	2%
2009	$41.14	$37.32	2%
2010	$41.96	$38.07	2%
2011	$42.80	$38.83	2%
2012	$43.66	$39.60	2%
2013	$44.53	$40.40	2%
2014	$45.42	$41.20	2%
2015	$46.33	$42.03	2%
2016	$47.26	$42.87	2%
2017	$48.20	$43.73	2%
2018	$49.16	$44.60	2%
2019	$50.15	$45.49	2%
2020	$51.15	$46.40	2%
2021	$52.17	$47.33	2%
2022	$53.22	$48.28	2%
2023	$54.28	$49.24	2%
2024	$55.37	$50.23	2%

Sutton Incremental Transportation Rates - Barge and Ocean Vessel Rates per Jerry Boyd

Barge Transportation

Year	$/ton	% increase
2003	$7.57	
2004	$7.72	2%
2005	$7.88	2%
2006	$8.03	2%
2007	$8.19	2%
2008	$8.36	2%
2009	$8.53	2%
2010	$8.70	2%
2011	$8.87	2%
2012	$9.05	2%
2013	$9.23	2%
2014	$9.41	2%
2015	$9.60	2%
2016	$9.79	2%
2017	$9.99	2%
2018	$10.19	2%
2019	$10.39	2%
2020	$10.60	2%
2021	$10.81	2%
2022	$11.03	2%
2023	$11.25	2%
2024	$11.47	2%

Ocean Vessel Transportation

Year	$/Metric Ton		$/ton
2003	$6.50		$5.90
2004	$6.63	2%	$6.01
2005	$6.76	2%	$6.13
2006	$6.90	2%	$6.26
2007	$7.04	2%	$6.38
2008	$7.18	2%	$6.51
2009	$7.32	2%	$6.64
2010	$7.47	2%	$6.77
2011	$7.62	2%	$6.91
2012	$7.77	2%	$7.05
2013	$7.92	2%	$7.19
2014	$8.08	2%	$7.33
2015	$8.24	2%	$7.48
2016	$8.41	2%	$7.63
2017	$8.58	2%	$7.78
2018	$8.75	2%	$7.94
2019	$8.92	2%	$8.09
2020	$9.10	2%	$8.26
2021	$9.28	2%	$8.42
2022	$9.47	2%	$8.59
2023	$9.66	2%	$8.76
2024	$9.85	2%	$8.94

Total Delivered Barge Incrementals

Total Incremental Price Delivered

BTU	**12800**	
SO2/mmBtu	**1.50**	
Year	$/ton	$/mmBtu
2004	$47.54	$1.8570
2005	$48.49	$1.8941
2006	$49.46	$1.9320
2007	$50.45	$1.9706
2008	$51.46	$2.0100
2009	$52.49	$2.0502
2010	$53.54	$2.0912
2011	$54.61	$2.1331
2012	$55.70	$2.1757
2013	$56.81	$2.2192
2014	$57.95	$2.2636
2015	$59.11	$2.3089
2016	$60.29	$2.3551
2017	$61.50	$2.4022
2018	$62.73	$2.4502
2019	$63.98	$2.4992
2020	$65.26	$2.5492
2021	$66.57	$2.6002
2022	$67.90	$2.6522
2023	$69.25	$2.7052
2024	$70.64	$2.7594

(Enter values for the Blue cells)

NUC 1-26a
AUGUST 2004
GFF

QUARTERLY COAL FORECAST - Base Case

Base Case ANNUAL AVERAGE SPOT PRICES - NOMINAL DOLLARS PER TON

	Year:	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017
	Northern Appalachia														
2.44	-1.6%, 13115 BTU	$58.50	$48.91	$48.84	$40.97	$38.01	$38.50	$39.27	$40.05	$40.85	$41.67	$42.50	$43.35	$44.22	$45.11
2.74	-1.8%, 13115 BTU	$58.50	$48.91	$48.84	$40.97	$38.01	$38.50	$39.27	$40.06	$40.86	$41.67	$42.51	$43.36	$44.22	$45.11
3.35	-2.5%, 13115 BTU	$58.50	$45.33	$45.26	$38.03	$35.32	$35.77	$36.49	$37.22	$37.96	$38.72	$39.49	$40.28	$41.09	$41.91
4.57	-3%, 13115 BTU	$53.50	$42.81	$42.73	$35.51	$32.80	$33.25	$33.92	$34.59	$35.29	$35.89	$36.71	$37.44	$38.19	$38.96
	Central Appalachia														
1.13	- 7%, 12400 BTU	$57.63	$60.40	$60.25	$47.89	$44.50	$46.39	$47.31	$48.26	$49.23	$50.21	$51.21	$52.24	$53.28	$54.35
1.20	- 7%, 13000 BTU	$60.11	$63.33	$63.17	$50.21	$46.65	$48.63	$49.60	$50.60	$51.61	$52.64	$53.69	$54.77	$55.86	$56.98
1.67	-1.0%, 12000 BTU	$59.05	$55.27	$55.15	$44.43	$40.99	$42.93	$43.79	$44.67	$45.56	$46.47	$47.40	$48.35	$49.31	$50.30
2.50	-1.5%, 12000 BTU	$56.67	$53.53	$53.23	$42.51	$39.07	$41.01	$41.83	$42.67	$43.52	$44.39	$45.28	$46.18	$47.11	$48.05
	Illinois Basin														
3.5	-3%, 11000 BTU (IL	$20.74	$20.14	$20.13	$20.63	$21.45	$22.41	$23.54	$24.55	$25.10	$25.58	$26.08	$26.63	$27.18	$27.77
2.5	-3%, 11000 BTU (K	$25.82	$35.29	$35.23	$29.99	$28.48	$29.32	$29.91	$30.50	$31.11	$31.74	$32.37	$33.02	$33.68	$34.35

	2018	2019	2020	2021	2022	2023	2024	2025
Northern Appalachia								
-1.6%, 13115 BTU	$46.01	$46.93	$47.87	$48.82	$49.80	$50.80	$51.81	$52.85
-1.8%, 13115 BTU	$46.01	$46.93	$47.87	$48.83	$49.80	$50.80	$51.82	$52.85
-2.5%, 13115 BTU	$42.75	$43.60	$44.48	$45.37	$46.27	$47.20	$48.14	$49.10
-3%, 13115 BTU	$39.74	$40.53	$41.34	$42.17	$43.01	$43.87	$44.75	$45.65
Central Appalachia								
- 7%, 12400 BTU	$55.44	$56.54	$57.68	$58.83	$60.01	$61.21	$62.43	$63.68
- 7%, 13000 BTU	$58.12	$59.28	$60.47	$61.68	$62.91	$64.17	$65.45	$66.76
-1.0%, 12000 BTU	$51.31	$52.33	$53.38	$54.45	$55.54	$56.65	$57.78	$58.94
-1.5%, 12000 BTU	$49.01	$49.99	$50.99	$52.01	$53.05	$54.11	$55.19	$56.30
Illinois Basin								
-3%, 11000 BTU (IL	$28.40	$29.07	$29.77	$30.48	$31.22	$31.97	$32.74	$33.53
-3%, 11000 BTU (K	$35.04	$35.74	$36.46	$37.18	$37.93	$38.69	$39.46	$40.25

Values highlighted in red not used in this data set

Northern Appalachia

	#SO2/mmBtu	BTU	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017
i	2.44	13115	$58.50	$48.91	$48.84	$40.97	$38.01	$38.50	$39.27	$40.05	$40.85	$41.67	$42.50	$43.35	$44.22	$45.11
2	2.74	13115	$58.50	$48.91	$48.84	$40.97	$38.01	$38.50	$39.27	$40.06	$40.86	$41.67	$42.51	$43.36	$44.22	$45.11
3	3.35	13115	$58.50	$45.33	$45.26	$38.03	$35.32	$35.77	$36.49	$37.22	$37.96	$38.72	$39.49	$40.28	$41.09	$41.91
4	4.57	13115	$53.50	$42.81	$42.73	$35.51	$32.80	$33.25	$33.92	$34.59	$35.29	$35.99	$36.71	$37.44	$38.19	$38.96

	2018	2019	2020	2021	2022	2023	2024	2025
i	$46.01	$46.93	$47.87	$48.82	$49.80	$50.80	$51.81	$52.85
2	$46.01	$46.93	$47.87	$48.83	$49.80	$50.80	$51.82	$52.85
3	$42.75	$43.60	$44.48	$45.37	$46.27	$47.20	$48.14	$49.10
4	$39.74	$40.53	$41.34	$42.17	$43.01	$43.87	$44.75	$45.65

Central Appalachia

	#SO2/mmBtu	BTU	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017
5	1.13	12400	$57.63	$60.40	$60.25	$47.89	$44.50	$46.39	$47.31	$48.26	$49.23	$50.21	$51.21	$52.24	$53.28	$54.35
6	1.20	12,500	$58.09	$60.89	$60.74	$48.28	$44.86	$46.76	$47.70	$48.65	$49.62	$50.61	$51.63	$52.66	$53.71	$54.79
7	1.67	12,000	$59.05	$55.27	$55.15	$44.43	$40.99	$42.93	$43.79	$44.67	$45.56	$46.47	$47.40	$48.35	$49.31	$50.30
8	1.67	12,500	$61.51	$57.57	$57.45	$46.28	$42.70	$44.72	$45.61	$46.53	$47.46	$48.41	$49.37	$50.36	$51.37	$52.40
9	2.50	12,000	$56.67	$53.53	$53.23	$42.51	$39.07	$41.01	$41.83	$42.67	$43.52	$44.39	$45.28	$46.18	$47.11	$49.05

	2018	2019	2020	2021	2022	2023	2024	2025
5	$55.44	$56.54	$57.68	$58.83	$60.01	$61.21	$62.43	$63.68
6	$55.88	$57.00	$58.14	$59.30	$60.49	$61.70	$62.93	$64.19
7	$51.31	$52.33	$53.38	$54.45	$55.54	$56.65	$57.78	$58.94
8	$53.44	$54.51	$55.60	$56.72	$57.85	$59.01	$60.19	$61.39
9	$49.01	$49.99	$50.89	$52.01	$53.05	$54.11	$55.19	$56.30

Illinois Basin

	#SO2/mmBtu	BTU	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017
	3.50	11000	$20.74	$20.14	$20.13	$20.63	$21.45	$22.41	$23.54	$24.55	$25.10	$25.58	$26.08	$26.63	$27.18	$27.77
11	3.50	11000	$25.82	$35.29	$35.23	$29.99	$28.48	$29.32	$29.91	$30.50	$31.11	$31.74	$32.37	$33.02	$33.68	$34.35

	2018	2019	2020	2021	2022	2023	2024	2025
	$28.40	$29.07	$29.77	$30.48	$31.22	$31.97	$32.74	$33.53
11	$35.04	$35.74	$36.46	$37.18	$37.93	$38.69	$39.46	$40.25

NAPP Coal ($/ton) Price Table

Coal Number for Scrubber Curves / Year	1	2	3	4
Average BTU/lb. coal	13,115	13,115	13,115	13,115
Average lbs. SO2/mmBTU	2.44	2.74	3.35	4.57
2004	$58.50	$58.50	$58.50	$53.50
2005	$48.91	$48.91	$45.33	$42.81
2006	$48.84	$48.84	$45.26	$42.73
2007	$40.97	$40.97	$38.03	$35.51
2008	$38.01	$38.01	$35.32	$32.80
2009	$38.50	$38.50	$35.77	$33.25
2010	$39.27	$39.27	$36.49	$33.92
2011	$40.05	$40.06	$37.22	$34.59
2012	$40.85	$40.86	$37.96	$35.29
2013	$41.67	$41.67	$38.72	$35.99
2014	$42.50	$42.51	$39.49	$36.71
2015	$43.35	$43.36	$40.28	$37.44
2016	$44.22	$44.22	$41.09	$38.19
2017	$45.11	$45.11	$41.91	$38.96
2018	$46.01	$46.01	$42.75	$39.74
2019	$46.93	$46.93	$43.60	$40.53
2020	$47.87	$47.87	$44.48	$41.34
2021	$48.82	$48.83	$45.37	$42.17
2022	$49.80	$49.80	$46.27	$43.01
2023	$50.80	$50.80	$47.20	$43.87
2024	$51.81	$51.82	$48.14	$44.75
2025	$52.85	$52.85	$49.10	$45.65

CAPP Coal ($/ton) Price Table

Year	5	6	7	8	9
Average BTU/lb. coal	12,400	12,500	12,000	12,500	12,000
Average lbs. SO2/mmBTU	1.13	1.20	1.67	1.67	2.50
2004	$57.63	$58.09	$59.05	$61.51	$56.67
2005	$60.40	$60.89	$55.27	$57.57	$53.53
2006	$60.25	$60.74	$55.15	$57.45	$53.23
2007	$47.89	$48.28	$44.43	$46.28	$42.51
2008	$44.50	$44.86	$40.99	$42.70	$39.07
2009	$46.39	$46.76	$42.93	$44.72	$41.01
2010	$47.31	$47.70	$43.79	$45.61	$41.83
2011	$48.26	$48.65	$44.67	$46.53	$42.67
2012	$49.23	$49.62	$45.56	$47.46	$43.52
2013	$50.21	$50.61	$46.47	$48.41	$44.39
2014	$51.21	$51.63	$47.40	$49.37	$45.28
2015	$52.24	$52.66	$48.35	$50.36	$46.18
2016	$53.28	$53.71	$49.31	$51.37	$47.11
2017	$54.35	$54.79	$50.30	$52.40	$48.05
2018	$55.44	$55.88	$51.31	$53.44	$49.01
2019	$56.54	$57.00	$52.33	$54.51	$49.99
2020	$57.68	$58.14	$53.38	$55.60	$50.99
2021	$58.83	$59.30	$54.45	$56.72	$52.01
2022	$60.01	$60.49	$55.54	$57.85	$53.05
2023	$61.21	$61.70	$56.65	$59.01	$54.11
2024	$62.43	$62.93	$57.78	$60.19	$55.19
2025	$63.68	$64.19	$58.94	$61.39	$56.30

Illinois Basin Coal ($/ton) Price Table

Year	11
Average BTU/lb. coal	11000
Average lbs. SO2/mmBTU	3.50
2004	$25.82
2005	$35.29
2006	$35.23
2007	$29.99
2008	$28.48
2009	$29.32
2010	$29.91
2011	$30.50
2012	$31.11
2013	$31.74
2014	$32.37
2015	$33.02
2016	$33.68
2017	$34.35
2018	$35.04
2019	$35.74
2020	$36.46
2021	$37.18
2022	$37.93
2023	$38.69
2024	$39.46
2025	$40.25

NAPP Coal ($/mmBtu) Price Table

Year				
Average BTU/lb. coal	13,115	13,115	13,115	13,115
Average lbs. SO2/mmBTU	2.44	2.74	3.35	4.57
2004	$2.23	$2.23	$2.23	$2.04
2005	$1.86	$1.86	$1.73	$1.63
2006	$1.86	$1.86	$1.73	$1.63
2007	$1.56	$1.56	$1.45	$1.35
2008	$1.45	$1.45	$1.35	$1.25
2009	$1.47	$1.47	$1.36	$1.27
2010	$1.50	$1.50	$1.39	$1.29
2011	$1.53	$1.53	$1.42	$1.32
2012	$1.56	$1.56	$1.45	$1.35
2013	$1.59	$1.59	$1.48	$1.37
2014	$1.62	$1.62	$1.51	$1.40
2015	$1.65	$1.65	$1.54	$1.43
2016	$1.69	$1.69	$1.57	$1.46
2017	$1.72	$1.72	$1.60	$1.49
2018	$1.75	$1.75	$1.63	$1.51
2019	$1.79	$1.79	$1.66	$1.55
2020	$1.82	$1.83	$1.70	$1.58
2021	$1.86	$1.86	$1.73	$1.61
2022	$1.90	$1.90	$1.76	$1.64
2023	$1.94	$1.94	$1.80	$1.67
2024	$1.98	$1.98	$1.84	$1.71
2025	$2.01	$2.01	$1.87	$1.74

CAPP Coal ($/mmBtu) Price Table

Year					
Average BTU/lb. coal	12,400	12,500	12,000	12,500	12,000
Average lbs. SO2/mmBTU	1.13	1.20	1.67	1.67	2.50
2004	$2.32	$2.32	$2.46	$2.46	$2.36
2005	$2.44	$2.44	$2.30	$2.30	$2.23
2006	$2.43	$2.43	$2.30	$2.30	$2.22
2007	$1.93	$1.93	$1.85	$1.85	$1.77
2008	$1.79	$1.79	$1.71	$1.71	$1.63
2009	$1.87	$1.87	$1.79	$1.79	$1.71
2010	$1.91	$1.91	$1.82	$1.82	$1.74
2011	$1.95	$1.95	$1.86	$1.86	$1.78
2012	$1.98	$1.98	$1.90	$1.90	$1.81
2013	$2.02	$2.02	$1.94	$1.94	$1.85
2014	$2.07	$2.07	$1.97	$1.97	$1.89
2015	$2.11	$2.11	$2.01	$2.01	$1.92
2016	$2.15	$2.15	$2.05	$2.05	$1.96
2017	$2.19	$2.19	$2.10	$2.10	$2.00
2018	$2.24	$2.24	$2.14	$2.14	$2.04
2019	$2.28	$2.28	$2.18	$2.18	$2.08
2020	$2.33	$2.33	$2.22	$2.22	$2.12
2021	$2.37	$2.37	$2.27	$2.27	$2.17
2022	$2.42	$2.42	$2.31	$2.31	$2.21
2023	$2.47	$2.47	$2.36	$2.36	$2.25
2024	$2.52	$2.52	$2.41	$2.41	$2.30
2025	$2.57	$2.57	$2.46	$2.46	$2.35

Illinois Basin ($/mmBtu) Price Table

Year	
Average BTU/lb. coal	11,000
Average lbs. SO2/mmBTU	3.50
2004	$1.17
2005	$1.60
2006	$1.60
2007	$1.36
2008	$1.29
2009	$1.33
2010	$1.36
2011	$1.39
2012	$1.41
2013	$1.44
2014	$1.47
2015	$1.50
2016	$1.53
2017	$1.56
2018	$1.59
2019	$1.62
2020	$1.66
2021	$1.69
2022	$1.72
2023	$1.76
2024	$1.79
2025	$1.83

NUC 1-38 a
AUGUST 2004 GFF

Sutton Incremental Barge Forecast (10)

Foreign coal incremental per recent quote (Evolution Markets and/or Glencor). When escalation rate in effect it is 2%.
Barge assumes a renegotiated rate of $6.00 st in 2006.

Year	Incremental $/mt 12800 1.5	$/ton 12800 1.5	% increase
2004	$69 52	$63 07	0%
2005	$69 52	$63 07	0%
2006	$69.52	$63 07	0%
2007	$55.27	$50.14	-21%
2008	$51.40	$46.63	-7%
2009	$52 43	$47.56	2%
2010	$53.47	$48.51	2%
2011	$54.54	$49 48	2%
2012	$55.63	$50.47	2%
2013	$56 75	$51 48	2%
2014	$57 88	$52.51	2%
2015	$59.04	$53.56	2%
2016	$60.22	$54 63	2%
2017	$61.42	$55.72	2%
2018	$62 65	$56.84	2%
2019	$63 91	$57.97	2%
2020	$65 18	$59 13	2%
2021	$66 49	$60.32	2%
2022	$67 82	$61.52	2%
2023	$69.17	$62.75	2%
2024	$70.56	$64 01	2%

$63 00 $69.52 $82 52

Sutton Incremental Transportation Rates - Barge and Ocean Vessel Rates per Jerry Boyd

Barge Transportation

Year	$/ton	% increase
0	$8.34	
2004	$8.34	2%
2005	$8.34	2%
2006	$6.00	2%
2007	$6.12	2%
2008	$6.24	2%
2009	$6.37	2%
2010	$6.49	2%
2011	$6.62	2%
2012	$6.76	2%
2013	$6.89	2%
2014	$7.03	2%
2015	$7.17	2%
2016	$7.31	2%
2017	$7.46	2%
2018	$7.61	2%
2019	$7.76	2%
2020	$7.92	2%
2021	$8.08	2%
2022	$8.24	2%
2023	$8.40	2%
2024	$8.57	2%

Ocean Vessel Transportation

Year	$/Metric Ton		$/ton
0	$13.00		$11.79
2004	$13.00	2%	$11.79
2005	$10.00	2%	$9.07
2006	$9.00	2%	$8 16
2007	$9.18	2%	$8.33
2008	$9.36	2%	$8.49
2009	$9.55	2%	$8.66
2010	$9.74	2%	$8 84
2011	$9.94	2%	$9 01
2012	$10.14	2%	$9.19
2013	$10.34	2%	$9 38
2014	$10.54	2%	$9.57
2015	$10.76	2%	$9.76
2016	$10.97	2%	$9 95
2017	$11.19	2%	$10.15
2018	$11.41	2%	$10 35
2019	$11.64	2%	$10.56
2020	$11.88	2%	$10 77
2021	$12.11	2%	$10 99
2022	$12.36	2%	$11.21
2023	$12.60	2%	$11 43
2024	$12.85	2%	$11 66

Total Delivered Barge Incrementals

Total Incremental Price Delivered

BTU 12800
SO2/mmBtu 1.50

Year	$/ton	$/mmBtu
2004	$83.20	$3.2499
2005	$80.48	$3.1436
2006	$77.29	$3.0168
2007	$64.58	$2.5228
2008	$61.36	$2.3970
2009	$62.59	$2 4450
2010	$63.84	$2 4939
2011	$65.12	$2.5438
2012	$66.42	$2 5946
2013	$67.75	$2.6465
2014	$69.11	$2.6994
2015	$70.49	$2.7534
2016	$71.90	$2.8085
2017	$73.34	$2.8647
2018	$74.80	$2.9220
2019	$76.30	$2.9804
2020	$77.82	$3.0400
2021	$79.38	$3.1008
2022	$80.97	$3.1628
2023	$82.59	$3.2261
2024	$84.24	$3.2906

November
2004 GFF

(Enter values for the Blue cells)

QUARTERLY COAL FORECAST - Base Case

Base Case — ANNUAL AVERAGE SPOT PRICES - NOMINAL DOLLARS PER TON

	Year:	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
	Northern Appalachia																						
2.44	-1.6%, 13115 BTU	$69.18	$60.70	$53.75	$47.01	$41.35	$40.70	$41.51	$42.34	$43.19	$44.05	$44.94	$45.83	$46.75	$47.69	$48.64	$49.61	$50.61	$51.62	$52.65	$53.70	$54.78	$55.87
2.74	-1.8%, 13115 BTU	$67.66	$59.13	$52.28	$45.50	$39.80	$39.10	$39.88	$40.68	$41.49	$42.32	$43.17	$44.03	$44.91	$45.81	$46.73	$47.66	$48.61	$49.59	$50.58	$51.59	$52.62	$53.67
3.35	-2.5%, 13115 BTU	$64.57	$54.94	$49.37	$44.03	$38.64	$38.10	$38.87	$39.64	$40.44	$41.24	$42.07	$42.91	$43.77	$44.64	$45.54	$46.45	$47.38	$48.32	$49.29	$50.28	$51.28	$52.31
4.57	-3%, 13115 BTU	$57.00	$48.54	$43.41	$37.90	$32.33	$31.59	$32.22	$32.87	$33.52	$34.20	$34.88	$35.58	$36.29	$37.01	$37.75	$38.51	$39.28	$40.07	$40.87	$41.68	$42.52	$43.37
	Central Appalachia																						
1.13	- 7%, 12400 BTU	$65.06	$64.68	$56.73	$48.82	$42.99	$42.21	$43.05	$43.91	$44.79	$45.68	$46.60	$47.53	$48.48	$49.45	$50.44	$51.45	$52.48	$53.53	$54.60	$55.69	$56.80	$57.94
converted to 1.2	- 78%, 13000 BTU	$65.25	$64.85	$56.86	$48.88	$42.99	$42.19	$43.03	$43.89	$44.77	$45.67	$46.58	$47.51	$48.46	$49.43	$50.42	$51.43	$52.46	$53.51	$54.58	$55.67	$56.78	$57.92
1.67	-1.0%, 12000 BTU	$65.19	$59.44	$52.48	$45.47	$39.93	$39.20	$39.98	$40.78	$41.60	$42.43	$43.28	$44.15	$45.03	$45.93	$46.85	$47.79	$48.74	$49.72	$50.71	$51.72	$52.76	$53.81
2.50	-1.5%, 12000 BTU	$61.34	$55.46	$48.76	$41.66	$36.01	$35.15	$35.85	$36.57	$37.30	$38.04	$38.80	$39.58	$40.37	$41.18	$42.00	$42.84	$43.70	$44.57	$45.47	$46.38	$47.30	$48.25
	Illinois Basin																						
3.5	-3%, 11000 BTU (IL)	$44.09	$42.09	$38.81	$36.07	$33.61	$33.42	$34.09	$34.77	$35.47	$36.18	$36.90	$37.64	$38.39	$39.16	$39.94	$40.74	$41.55	$42.39	$43.23	$44.10	$44.98	$45.88
2.5	-3%, 11000 BTU (KY)	$25.82	$35.29	$35.23	$29.99	$28.48	$29.32	$29.91	$30.50	$31.11	$31.74	$32.37	$33.02	$33.68	$34.35	$35.04	$35.74	$36.46	$37.18	$37.93	$38.69	$39.46	$40.25

Northern Appalachia

	#SO2/mmBtu	BTU	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
i	2.44	13115	$69.18	$60.70	$53.75	$47.01	$41.35	$40.70	$41.51	$42.34	$43.19	$44.05	$44.94	$45.83	$46.75	$47.69	$48.64	$49.61	$50.61	$51.62	$52.65	$53.70	$54.78	$55.87
2	2.74	13115	$67.66	$59.13	$52.28	$45.50	$39.80	$39.10	$39.88	$40.68	$41.49	$42.32	$43.17	$44.03	$44.91	$45.81	$46.73	$47.66	$48.61	$49.59	$50.58	$51.59	$52.62	$53.67
3	3.35	13115	$64.57	$54.94	$49.37	$44.03	$38.64	$38.10	$38.87	$39.64	$40.44	$41.24	$42.07	$42.91	$43.77	$44.64	$45.54	$46.45	$47.38	$48.32	$49.29	$50.28	$51.28	$52.31
4	4.57	13115	$57.00	$48.54	$43.41	$37.90	$32.33	$31.59	$32.22	$32.87	$33.52	$34.20	$34.88	$35.58	$36.29	$37.01	$37.75	$38.51	$39.28	$40.07	$40.87	$41.68	$42.52	$43.37

Central Appalachia

	#SO2/mmBtu	BTU	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
5	1.13	12400	$65.06	$64.68	$56.73	$48.82	$42.99	$42.21	$43.05	$43.91	$44.79	$45.68	$46.60	$47.53	$48.48	$49.45	$50.44	$51.45	$52.48	$53.53	$54.60	$55.69	$56.80	$57.94
6	1.20	12,500	$65.25	$64.85	$56.86	$48.88	$42.99	$42.19	$43.03	$43.89	$44.77	$45.67	$46.58	$47.51	$48.46	$49.43	$50.42	$51.43	$52.46	$53.51	$54.58	$55.67	$56.78	$57.92
7	1.67	12,000	$65.19	$59.44	$52.48	$45.47	$39.93	$39.20	$39.98	$40.78	$41.60	$42.43	$43.28	$44.15	$45.03	$45.93	$46.85	$47.79	$48.74	$49.72	$50.71	$51.72	$52.76	$53.81
8	1.67	12,500	$67.91	$61.92	$54.66	$47.36	$41.60	$40.83	$41.65	$42.48	$43.33	$44.20	$45.08	$45.99	$46.91	$47.84	$48.80	$49.78	$50.77	$51.79	$52.82	$53.88	$54.96	$56.06
9	2.50	12,000	$61.34	$55.46	$48.76	$41.66	$36.01	$35.15	$35.85	$36.57	$37.30	$38.04	$38.80	$39.58	$40.37	$41.18	$42.00	$42.84	$43.70	$44.57	$45.47	$46.38	$47.30	$48.25

Illinois Basin

	#SO2/mmBtu	BTU	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
11	3.50	11000	$44.09	$42.09	$38.81	$36.07	$33.61	$33.42	$34.09	$34.77	$35.47	$36.18	$36.90	$37.64	$38.39	$39.16	$39.94	$40.74	$41.55	$42.39	$43.23	$44.10	$44.98	$45.88

NAPP Coal ($/ton) Price Table

Coal Number for Scrubber Curves / Year	1	2	3	4
Average BTU/lb. coal	13,115	13,115	13,115	13,115
Average lbs SO2/mmBTU	2.44	2.74	3.35	4.57
2004	$69.18	$67.66	$64.57	$57.00
2005	$60.70	$59.13	$54.94	$48.54
2006	$53.75	$52.28	$49.37	$43.41
2007	$47.01	$45.50	$44.03	$37.90
2008	$41.35	$39.80	$38.64	$32.33
2009	$40.70	$39.10	$38.10	$31.59
2010	$41.51	$39.88	$38.87	$32.22
2011	$42.34	$40.68	$39.64	$32.87
2012	$43.19	$41.49	$40.44	$33.52
2013	$44.05	$42.32	$41.24	$34.20
2014	$44.94	$43.17	$42.07	$34.88
2015	$45.83	$44.03	$42.91	$35.58
2016	$46.75	$44.91	$43.77	$36.29
2017	$47.69	$45.81	$44.64	$37.01
2018	$48.64	$46.73	$45.54	$37.75
2019	$49.61	$47.66	$46.45	$38.51
2020	$50.61	$48.61	$47.38	$39.28
2021	$51.62	$49.59	$48.32	$40.07
2022	$52.65	$50.58	$49.29	$40.87
2023	$53.70	$51.59	$50.28	$41.68
2024	$54.78	$52.62	$51.28	$42.52
2025	$55.87	$53.67	$52.31	$43.37

CAPP Coal ($/ton) Price Table

Year	5	6	7	8	9
Average BTU/lb. coal	12,400	12,500	12,000	12,500	12,000
Average lbs. SO2/mmBTU	1.13	1.20	1.67	1.67	2.50
2004	$65.06	$65.25	$65.19	$67.91	$61.34
2005	$64.68	$64.85	$59.44	$61.92	$55.46
2006	$56.73	$56.86	$52.48	$54.66	$48.76
2007	$48.82	$48.88	$45.47	$47.36	$41.66
2008	$42.99	$42.99	$39.93	$41.60	$36.01
2009	$42.21	$42.19	$39.20	$40.83	$35.15
2010	$43.05	$43.03	$39.98	$41.65	$35.85
2011	$43.91	$43.89	$40.78	$42.48	$36.57
2012	$44.79	$44.77	$41.60	$43.33	$37.30
2013	$45.68	$45.67	$42.43	$44.20	$38.04
2014	$46.60	$46.58	$43.28	$45.08	$38.80
2015	$47.53	$47.51	$44.15	$45.99	$39.58
2016	$48.48	$48.46	$45.03	$46.91	$40.37
2017	$49.45	$49.43	$45.93	$47.84	$41.18
2018	$50.44	$50.42	$46.85	$48.80	$42.00
2019	$51.45	$51.43	$47.79	$49.78	$42.84
2020	$52.48	$52.46	$48.74	$50.77	$43.70
2021	$53.53	$53.51	$49.72	$51.79	$44.57
2022	$54.60	$54.58	$50.71	$52.82	$45.47
2023	$55.69	$55.67	$51.72	$53.88	$46.38
2024	$56.80	$56.78	$52.76	$54.96	$47.30
2025	$57.94	$57.92	$53.81	$56.06	$48.25

Illinois Basin Coal ($/ton) Price Table

Year	11
Average BTU/lb. coal	11000
Average lbs. SO2/mmBTU	3.50
2004	$44.09
2005	$42.09
2006	$38.81
2007	$36.07
2008	$33.61
2009	$33.42
2010	$34.09
2011	$34.77
2012	$35.47
2013	$36.18
2014	$36.90
2015	$37.64
2016	$38.39
2017	$39.16
2018	$39.94
2019	$40.74
2020	$41.55
2021	$42.39
2022	$43.23
2023	$44.10
2024	$44.98
2025	$45.88

NAPP Coal ($/mmBtu) Price Table

Year				
Average BTU/lb. coal	13,115	13,115	13,115	13,115
Average lbs. SO2/mmBTU	2.44	2.74	3.35	4.57
2004	$2.64	$2.58	$2.46	$2.17
2005	$2.31	$2.25	$2.09	$1.85
2006	$2.05	$1.99	$1.88	$1.65
2007	$1.79	$1.73	$1.68	$1.45
2008	$1.58	$1.52	$1.47	$1.23
2009	$1.55	$1.49	$1.45	$1.20
2010	$1.58	$1.52	$1.48	$1.23
2011	$1.61	$1.55	$1.51	$1.25
2012	$1.65	$1.58	$1.54	$1.28
2013	$1.68	$1.61	$1.57	$1.30
2014	$1.71	$1.65	$1.60	$1.33
2015	$1.75	$1.68	$1.64	$1.36
2016	$1.76	$1.71	$1.67	$1.38
2017	$1.82	$1.75	$1.70	$1.41
2018	$1.85	$1.78	$1.74	$1.44
2019	$1.89	$1.82	$1.77	$1.47
2020	$1.93	$1.85	$1.81	$1.50
2021	$1.97	$1.89	$1.84	$1.53
2022	$2.01	$1.93	$1.88	$1.56
2023	$2.05	$1.97	$1.92	$1.59
2024	$2.09	$2.01	$1.96	$1.62
2025	$2.13	$2.05	$1.99	$1.65

CAPP Coal ($/mmBtu) Price Table

Year					
Average BTU/lb. coal	12,400	12,500	12,000	12,500	12,000
Average lbs. SO2/mmBTU	1.13	1.20	1.67	1.67	2.50
2004	$2.62	$2.61	$2.72	$2.72	$2.56
2005	$2.61	$2.59	$2.48	$2.48	$2.31
2006	$2.29	$2.27	$2.19	$2.19	$2.03
2007	$1.97	$1.96	$1.89	$1.89	$1.74
2008	$1.73	$1.72	$1.66	$1.66	$1.50
2009	$1.70	$1.69	$1.63	$1.63	$1.46
2010	$1.74	$1.72	$1.67	$1.67	$1.49
2011	$1.77	$1.76	$1.70	$1.70	$1.52
2012	$1.81	$1.79	$1.73	$1.73	$1.55
2013	$1.84	$1.83	$1.77	$1.77	$1.59
2014	$1.88	$1.86	$1.80	$1.80	$1.62
2015	$1.92	$1.90	$1.84	$1.84	$1.65
2016	$1.95	$1.94	$1.88	$1.88	$1.68
2017	$1.99	$1.98	$1.91	$1.91	$1.72
2018	$2.03	$2.02	$1.95	$1.95	$1.75
2019	$2.07	$2.06	$1.99	$1.99	$1.79
2020	$2.12	$2.10	$2.03	$2.03	$1.82
2021	$2.16	$2.14	$2.07	$2.07	$1.86
2022	$2.20	$2.18	$2.11	$2.11	$1.89
2023	$2.25	$2.23	$2.16	$2.16	$1.93
2024	$2.29	$2.27	$2.20	$2.20	$1.97
2025	$2.34	$2.32	$2.24	$2.24	$2.01

Illinois Basin ($/mmBtu) Price Table

Year	
	11,000
	3.50
2004	$2.00
2005	$1.91
2006	$1.76
2007	$1.64
2008	$1.53
2009	$1.52
2010	$1.55
2011	$1.58
2012	$1.61
2013	$1.64
2014	$1.68
2015	$1.71
2016	$1.74
2017	$1.78
2018	$1.82
2019	$1.82
2020	$1.85
2021	$1.89
2022	$1.93
2023	$1.97
2024	$2.00
2025	$2.04

Prepared by: Anne Taylor Boggs
Prepared on: 09.08.2004
Concurring Manager: Bill Knight

Department: Fossil Fuels Department

Approval Date: 09.14.2004
Updated 10/5/2004 BAC

Spot Coal Prices determined for each plant by the following:
- NAPP, CAPP, and Colorado spot prices for 2004 taken from United Daily 09.08.2004 (we had no 2004 forecast for 2.2# Capp, pricing based on $3.50 premium over 2005 pricing)
- All spot prices 2005 - 2009 taken from Henwood 09.22.2004 Forecast Update
- Illinois Basin 2004 pricing based on $2/ton premium over 2005 Henwood pricing
- 2% escalation of Henwood forecast used for 2010 and beyond
- Sensitivity analysis will use an 80% bandwith (90% confidence level high and 10% confidence level low)
- John Dean forecast not used in this data

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Sutton Incremental Barge Forecast (10)

Foreign coal incremental per recent quote (Evolution Markets and/or Glencor). When escalation rate in effect it is 2%.
Ocean Freight, quoted 09/13/2004 Eitzen-Bulk through 2008. Todays market 25,500 pd.
Barge fixed through 2006, 2% esclation through 2024, andassumes a renegotiated rate of $6.00 st in 2006.

Year	Incremental $/mt 12800 1.2	$/ton 12800 1.2	% increase
2004	$69.52	$63.07	0%
2005	$69.52	$63.07	0%
2006	$69.52	$63.07	0%
2007	$55.27	$50.14	-21%
2008	$51.40	$46.63	-7%
2009	$52.43	$47.56	2%
2010	$53.47	$48.51	2%
2011	$54.54	$49.48	2%
2012	$55.63	$50.47	2%
2013	$56.75	$51.48	2%
2014	$57.88	$52.51	2%
2015	$59.04	$53.56	2%
2016	$60.22	$54.63	2%
2017	$61.42	$55.72	2%
2018	$62.65	$56.84	2%
2019	$63.91	$57.97	2%
2020	$65.18	$59.13	2%
2021	$66.49	$60.32	2%
2022	$67.82	$61.52	2%
2023	$69.17	$62.75	2%
2024	$70.56	$64.01	2%

$63.00 $69.52 $82.52

Sutton Incremental Transportation Rates - Barge and Ocean Vessel Rates per Jerry Boyd

Barge Transportation

Year	$/ton	% increase
0	$8.34	
2004	$8.34	2%
2005	$8.34	2%
2006	$6.00	2%
2007	$6.12	2%
2008	$6.24	2%
2009	$6.37	2%
2010	$6.49	2%
2011	$6.62	2%
2012	$6.76	2%
2013	$6.89	2%
2014	$7.03	2%
2015	$7.17	2%
2016	$7.31	2%
2017	$7.46	2%
2018	$7.61	2%
2019	$7.76	2%
2020	$7.92	2%
2021	$8.08	2%
2022	$8.24	2%
2023	$8.40	2%
2024	$8.57	2%

Ocean Vessel Transportation

Year	$/Metric Ton		$/ton
0	$13.00		$11.79
2004	$17.00	2%	$15.42
2005	$12.95	2%	$11.75
2006	$10.50	2%	$9.53
2007	$9.50	2%	$8.62
2008	$9.50	2%	$8.62
2009	$9.69	2%	$8.79
2010	$9.88	2%	$8.97
2011	$10.08	2%	$9.15
2012	$10.28	2%	$9.33
2013	$10.49	2%	$9.52
2014	$10.70	2%	$9.71
2015	$10.91	2%	$9.90
2016	$11.13	2%	$10.10
2017	$11.35	2%	$10.30
2018	$11.58	2%	$10.51
2019	$11.81	2%	$10.72
2020	$12.05	2%	$10.93
2021	$12.29	2%	$11.15
2022	$12.54	2%	$11.37
2023	$12.79	2%	$11.60
2024	$13.04	2%	$11.83

Total Delivered Barge Incrementals

Total Incremental Price Delivered

BTU **12800**
SO2/mmBtu **1.50**

Year	$/ton	$/mmBtu
Coal Number for Scrubber Curves	**10**	
2004	$86.83	$3.392
2005	$83.15	$3.248
2006	$78.59	$3.070
2007	$64.87	$2.534
2008	$61.49	$2.402
2009	$62.72	$2.450
2010	$63.97	$2.499
2011	$65.25	$2.549
2012	$66.56	$2.600
2013	$67.89	$2.652
2014	$69.25	$2.705
2015	$70.63	$2.759
2016	$72.04	$2.814
2017	$73.48	$2.870
2018	$74.95	$2.928
2019	$76.45	$2.986
2020	$77.98	$3.046
2021	$79.54	$3.107
2022	$81.13	$3.169
2023	$82.75	$3.233
2024	$84.41	$3.297

Barge & Ocean Rates:

Prepared By:	Jason Duttinger
Date:	9/13/2004
Approved By:	Jerry Boyd
Date:	09/13/04
Department:	FFD

Import Coal Prices:

Prepared By:	Barbara Coppola
Date:	9/6/2004
Approved By:	Bill Knight
Date:	09/15/04
Department:	FFD

LWC 1-38.a
APRIL 2005 GFF

QUARTERLY COAL FORECAST - Base Case

Base Case ANNUAL AVERAGE MARKET PRICES - NOMINAL DOLLARS PER TON

		Year:	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
1	3.00	Low Sulfur, 13000 Btu	55.92	57.29	51.50	43.19	39.57	40.51	41.90	43.11	44.74	46.20	47.48	48.87	50.27	51.56	52.72	54.11	56.10	57.92	59.59	61.38	62.81	64.46
2	4.00	Mid Sulfur, 13000 Btu	49.55	50.20	45.29	38.53	35.56	36.41	37.65	38.74	40.21	41.51	42.66	43.91	45.17	46.33	47.38	48.62	50.41	52.05	53.55	55.16	56.44	57.93
3	1.60	Low Sulfur, 12500 Btu, CSX	53.86	54.32	49.21	41.99	38.82	39.75	41.11	42.30	43.90	45.32	46.58	47.94	49.32	50.58	51.73	53.08	55.04	56.82	58.46	60.22	61.62	63.24
4	1.60	Low Sulfur, 12500 Btu, NS	57.25	57.67	51.70	43.28	39.59	40.53	41.92	43.13	44.76	46.21	47.50	48.88	50.29	51.57	52.74	54.12	56.12	57.94	59.61	61.40	62.83	64.49
5	1.20	Compliance, 12500 Btu, CSX	58.80	59.60	53.92	45.52	41.84	42.84	44.30	45.58	47.31	48.84	50.20	51.67	53.15	54.51	55.75	57.21	59.31	61.24	63.01	64.90	66.41	68.16
6	1.20	Compliance, 12500 Btu, NS	61.67	62.28	55.74	46.35	42.25	43.25	44.73	46.03	47.77	49.32	50.69	52.17	53.67	55.04	56.29	57.76	59.89	61.83	63.62	65.53	67.05	68.82
7	2.20	Mid Sulfur, 12500 Btu, CSX	51.69	52.18	47.40	40.51	37.46	38.35	39.67	40.81	42.36	43.73	44.95	46.26	47.59	48.81	49.91	51.22	53.11	54.83	56.41	58.11	59.46	61.02
8	2.20	Mid Sulfur, 13000 Btu, NS	57.25	57.57	51.33	42.82	39.17	40.10	41.48	42.67	44.29	45.73	47.00	48.37	49.76	51.03	52.19	53.56	55.53	57.33	58.99	60.76	62.17	63.81
9	2.50	Low Sulfur, 11900 Btu	47.34	49.70	46.02	39.23	36.05	36.97	38.32	39.50	41.09	42.51	43.76	45.11	46.48	47.73	48.87	50.21	52.16	53.93	55.56	57.30	58.69	60.31
10	3.50	High Sulfur, 11900 Btu	42.17	43.86	41.01	35.66	33.09	33.94	35.18	36.27	37.74	39.05	40.20	41.45	42.71	43.87	44.92	46.16	47.95	49.59	51.09	52.70	53.99	55.48
12	1.00	High Btu, 12000 Btu	30.01	32.16	30.28	27.12	25.68	26.29	27.19	27.98	29.04	29.98	30.81	31.71	32.62	33.46	34.22	35.11	36.41	37.59	38.67	39.83	40.76	41.84
13	1.00	Low Btu, 11300 Btu	26.25	28.12	26.57	23.94	22.72	23.26	24.06	24.75	25.69	26.52	27.26	28.06	28.86	29.60	30.27	31.07	32.21	33.26	34.22	35.24	36.06	37.01
11	1.20	Import Compliance, 12,400 Btu	60.27	59.36	55.05	51.42	52.45	53.50	54.57	55.66	56.78	57.91	59.07	60.25	61.46	62.69	63.94	65.22	66.52	67.85	69.21	70.60	72.01	73.45

NAPP Coal ($/ton) Price Table

Year	Low Sulfur, 13	Mid Sulfur, 13000 Btu
2005	$55.92	$49.55
2006	$57.29	$50.20
2007	$51.50	$45.29
2008	$43.19	$38.53
2009	$39.57	$35.56
2010	$40.51	$36.41
2011	$41.90	$37.65
2012	$43.11	$38.74
2013	$44.74	$40.21
2014	$46.20	$41.51
2015	$47.48	$42.66
2016	$48.87	$43.91
2017	$50.27	$45.17
2018	$51.56	$46.33
2019	$52.72	$47.38
2020	$54.11	$48.62
2021	$56.10	$50.41
2022	$57.92	$52.05
2023	$59.59	$53.55
2024	$61.38	$55.16
2025	$62.81	$56.44
2026	$64.46	$57.93

CAPP Coal ($/ton) Price Table

Year	Low Sulfur, 12	Low Sulfur, 1	Compliance,	Compliance,	Mid Sulfur,	Mid Sulfur, 13000 Btu, NS
	$53.86	$57.25	$58.80	$61.67	$51.69	$57.25
	$54.32	$57.67	$59.60	$62.28	$52.18	$57.57
	$49.21	$51.70	$53.92	$55.74	$47.40	$51.33
	$41.99	$43.28	$45.52	$46.35	$40.51	$42.82
	$38.82	$39.59	$41.84	$42.25	$37.46	$39.17
	$39.75	$40.53	$42.84	$43.25	$38.35	$40.10
	$41.11	$41.92	$44.30	$44.73	$39.67	$41.48
	$42.30	$43.13	$45.58	$46.03	$40.81	$42.67
	$43.90	$44.76	$47.31	$47.77	$42.36	$44.29
	$45.32	$46.21	$48.84	$49.32	$43.73	$45.73
	$46.58	$47.50	$50.20	$50.69	$44.95	$47.00
	$47.94	$48.88	$51.67	$52.17	$46.26	$48.37
	$49.32	$50.29	$53.15	$53.67	$47.59	$49.76
	$50.58	$51.57	$54.51	$55.04	$48.81	$51.03
	$51.73	$52.74	$55.75	$56.29	$49.91	$52.19
	$53.08	$54.12	$57.21	$57.76	$51.22	$53.56
	$55.04	$56.12	$59.31	$59.89	$53.11	$55.53
	$56.82	$57.94	$61.24	$61.83	$54.83	$57.33
	$58.46	$59.61	$63.01	$63.62	$56.41	$58.99
	$60.22	$61.40	$64.90	$65.53	$58.11	$60.76
	$61.62	$62.83	$66.41	$67.05	$59.46	$62.17
	$63.24	$64.49	$68.16	$68.82	$61.02	$63.81

Illinois Basin Coal ($/ton) Price / Import

Year	Low Sulfur, 1	High Sulfur,	Compliance, 12,400 Btu
	$47.34	$42.17	$60.27
	$49.70	$43.86	$59.36
	$46.02	$41.01	$55.05
	$39.23	$35.66	$51.42
	$36.05	$33.09	$52.45
	$36.97	$33.94	$53.50
	$38.32	$35.18	$54.57
	$39.50	$36.27	$55.66
	$41.09	$37.74	$56.78
	$42.51	$39.05	$57.91
	$43.76	$40.20	$59.07
	$45.11	$41.45	$60.25
	$46.48	$42.71	$61.46
	$47.73	$43.87	$62.69
	$48,87	$44.92	$63.94
	$50.21	$46.16	$65.22
	$52.16	$47.95	$66.52
	$53.93	$49.59	$67.85
	$55.56	$51.09	$69.21
	$57.30	$52.70	$70.60
	$58.69	$53.99	$72.01
	$60.31	$55.48	$73.45

Colorado Coal ($/ton) Price Table

Year	High Btu, 12	Low Btu, 11300 Btu
	$30.01	$26.25
	$32.16	$28.12
	$30.28	$26.57
	$27.12	$23.94
	$25.68	$22.72
	$26.29	$23.26
	$27.19	$24.06
	$27.98	$24.75
	$29.04	$25.69
	$29.98	$26.52
	$30.81	$27.26
	$31.71	$28.06
	$32.62	$28.86
	$33.46	$29.60
	$34.22	$30.27
	$35.11	$31.07
	$36.41	$32.21
	$37.59	$33.26
	$38.67	$34.22
	$39.83	$35.24
	$40.76	$36.06
	$41.84	$37.01

NAPP Coal ($/mmBtu) Price Table

Year	1 Low Sulfur, 13	2 Mid Sulfur, 13000 Btu
2005	$2.151	$1.906
2006	$2.204	$1.931
2007	$1.981	$1.742
2008	$1.661	$1.482
2009	$1.522	$1.368
2010	$1.558	$1.400
2011	$1.612	$1.448
2012	$1.658	$1.490
2013	$1.721	$1.546
2014	$1.777	$1.597
2015	$1.826	$1.641
2016	$1.879	$1.689
2017	$1.934	$1.737
2018	$1.983	$1.782
2019	$2.028	$1.822
2020	$2.081	$1.870
2021	$2.156	$1.939
2022	$2.228	$2.002
2023	$2.292	$2.060
2024	$2.361	$2.121
2025	$2.416	$2.171
2026	$2.479	$2.228

CAPP Coal ($/mmBtu) Price Table

Year	3 Low Sulfur, 12	4 Low Sulfur, 1	5 Compliance,	6 Compliance,	7 Mid Sulfur,	8 Mid Sulfur, 13000 Btu, NS
2005	$2.154	$2.290	$2.352	$2.467	$2.068	$2.202
2006	$2.173	$2.307	$2.384	$2.491	$2.087	$2.214
2007	$1.969	$2.068	$2.157	$2.230	$1.896	$1.974
2008	$1.679	$1.731	$1.821	$1.854	$1.621	$1.647
2009	$1.553	$1.583	$1.674	$1.690	$1.498	$1.507
2010	$1.590	$1.621	$1.713	$1.730	$1.534	$1.542
2011	$1.644	$1.677	$1.772	$1.789	$1.587	$1.595
2012	$1.692	$1.725	$1.823	$1.841	$1.632	$1.641
2013	$1.756	$1.790	$1.892	$1.911	$1.694	$1.703
2014	$1.813	$1.848	$1.954	$1.973	$1.749	$1.759
2015	$1.863	$1.900	$2.008	$2.028	$1.798	$1.808
2016	$1.918	$1.955	$2.067	$2.087	$1.850	$1.860
2017	$1.973	$2.011	$2.126	$2.147	$1.904	$1.914
2018	$2.023	$2.063	$2.180	$2.202	$1.952	$1.963
2019	$2.069	$2.110	$2.230	$2.251	$1.996	$2.007
2020	$2.123	$2.165	$2.288	$2.310	$2.049	$2.060
2021	$2.201	$2.245	$2.373	$2.396	$2.124	$2.136
2022	$2.273	$2.318	$2.450	$2.473	$2.193	$2.205
2023	$2.339	$2.384	$2.520	$2.545	$2.256	$2.269
2024	$2.409	$2.456	$2.596	$2.621	$2.324	$2.337
2025	$2.465	$2.513	$2.656	$2.682	$2.378	$2.391
2026	$2.530	$2.579	$2.726	$2.753	$2.441	$2.454

Illinois Basin Coal ($/mmBtu) Price / Import

Year	9 Low Sulfur, 1	10 High Sulfur,	11 Compliance, 12,400 Btu
2005	$1.989	$1.772	$2.430
2006	$2.088	$1.843	$2.394
2007	$1.934	$1.723	$2.220
2008	$1.648	$1.498	$2.074
2009	$1.515	$1.390	$2.115
2010	$1.553	$1.426	$2.157
2011	$1.610	$1.478	$2.201
2012	$1.660	$1.524	$2.245
2013	$1.727	$1.586	$2.289
2014	$1.786	$1.641	$2.335
2015	$1.839	$1.689	$2.382
2016	$1.895	$1.741	$2.430
2017	$1.953	$1.795	$2.478
2018	$2.005	$1.843	$2.528
2019	$2.053	$1.887	$2.578
2020	$2.110	$1.939	$2.630
2021	$2.191	$2.015	$2.682
2022	$2.266	$2.084	$2.736
2023	$2.334	$2.147	$2.791
2024	$2.408	$2.214	$2.847
2025	$2.466	$2.268	$2.904
2026	$2.534	$2.331	$2.962

Colorado Coal ($/mmBtu) Price

Year	12 High Btu, 12	13 Low Btu, 11300 Btu
2005	$1.250	$1.161
2006	$1.340	$1.244
2007	$1.262	$1.176
2008	$1.130	$1.059
2009	$1.070	$1.005
2010	$1.096	$1.029
2011	$1.133	$1.065
2012	$1.166	$1.095
2013	$1.210	$1.137
2014	$1.249	$1.174
2015	$1.284	$1.206
2016	$1.321	$1.241
2017	$1.359	$1.277
2018	$1.394	$1.310
2019	$1.426	$1.340
2020	$1.463	$1.375
2021	$1.517	$1.425
2022	$1.566	$1.472
2023	$1.611	$1.514
2024	$1.660	$1.559
2025	$1.698	$1.596
2026	$1.743	$1.638

Spot Coal Prices determined for each plant by the following

Department. Regulated Fuels Department

Prepared by: Barbara Coppola
Prepared on: 02.16.2005
Concurring Manager: Bill Knight

ZARNIKAU

EXHIBIT NO. 11

NYMEX Henry Hub Gas Futures
May 10, 2005 Settlement
Source: Platt's Gas Daily

	Settlement Price		
Jul-05	6.788		
Aug-05	6.863		
Sep-05	6.913		
Oct-05	6.970		
Nov-05	7.415		
Dec-05	7.830		
Jan-06	8.090		
Feb-06	8.085		
Mar-06	7.935		
Apr-06	6.895		
May-06	6.765		
Jun-06	6.812		
		Avg:	**7.280**

ZARNIKAU

EXHIBIT NO. 12

PEC's Proposed Historical Test Period System Fuel Cost

Source: Barkley Exhibit No. 1

	Total Fuel Cost	Total KWH Sales	$/KWH
Jan-04	$ 70,891,018.16	4,530,204,500	$ 0.01565
Feb-04	$ 62,604,037.53	4,578,139,300	$ 0.01367
Mar-04	$ 59,343,822.43	4,185,739,500	$ 0.01418
Apr-04	$ 51,151,950.17	3,848,207,000	$ 0.01329
May-04	$ 102,888,538.96	3,788,221,700	$ 0.02716
Jun-04	$ 76,744,913.67	4,658,707,300	$ 0.01647
Jul-04	$ 94,676,400.17	4,912,347,500	$ 0.01927
Aug-04	$ 94,485,361.07	4,826,877,000	$ 0.01957
Sep-04	$ 76,778,917.70	4,575,050,600	$ 0.01678
Oct-04	$ 55,096,823.43	3,917,029,600	$ 0.01407
Nov-04	$ 60,654,124.23	3,717,156,100	$ 0.01632
Dec-04	$ 77,843,045.33	4,286,650,200	$ 0.01816
Jan-05	$ 90,352,976.19	4,550,908,200	$ 0.01985
Feb-05	$ 73,056,297.12	4,522,714,100	$ 0.01615
Mar-05	$ 86,349,022.37	4,317,282,100	$ 0.02000
TOTAL	$ 1,132,917,248.53	65,215,234,700	$ 0.01737

BEFORE THE
PUBLIC SERVICE COMMISSION OF
SOUTH CAROLINA

DOCKET NO. 2005-1-E

In the Matter of:	)	
	)	
Carolina Power & Light Company d/b/a	)	**CERTIFICATE OF SERVICE**
Progress Energy Carolinas, Inc.	)	
Annual Review of Base Rates	)	
For Fuel Costs	)	

This is to certify that the foregoing document was served upon the following parties at the addresses set forth by first-class mail, postage pre-paid this 11th day of May, 2005:

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